Schedule 13
Change Request for FY 08-09 Budget Request Cycle

Decision Item FY 08-09 ☐ Base Reduction Item FY 08-09 ☐ Supplemental FY 07-08 ☐ Budget Request Amendment FY 08-09 ☑

Request Title: Additional FTE to Address OGCC's Workload and Changing Mission

Department: Natural Resources

Priority Number: 1a of 24

Dept. Approval by: Will H. Levine **Date:** 1-19-2008

OSPB Approval: [signature] **Date:** 1-18-08

	Fund	1 Prior-Year Actual FY 06-07	2 Appropriation FY 07-08	3 Supplemental Request FY 07-08	4 Total Revised Request FY 07-08	5 Base Request FY 08-09	6 Decision/ Base Reduction FY 08-09	7 November 1 Request FY 08-09	8 Budget Amendment FY 08-09	9 Total Revised Request FY 08-09	10 Change from Base (Column 5) FY 09-10
Total of All Line Items	Total	8,270,280	9,484,916	0	9,484,916	9,987,800	778,768	10,766,568	1,142,472	11,861,040	1,840,050
	FTE	47.00	53.00	0.00	53.00	53.00	9.00	62.00	12.00	74.00	21.00
	GF	1,485,229	1,129,728	0	1,129,728	1,325,217	0	1,325,217	0	1,325,217	0
	GFE	0	0	0	0	0	0	0	0	0	0
	CF	2,761,266	5,317,174	0	5,317,174	5,679,432	778,768	6,458,200	1,142,472	7,552,672	1,840,050
	CFE	3,915,355	2,836,120	0	2,836,120	2,743,517	0	2,743,517	0	2,743,517	0
	FF	108,430	201,894	0	201,894	239,634	0	239,634	0	239,634	0
(4) Oil and Gas Conservation Commission Program Costs	Total	4,457,447	4,862,468	0	4,862,468	4,675,823	757,224	5,433,047	984,512	6,417,559	1,688,172
	FTE	47.00	53.00	0.00	53.00	53.00	9.00	62.00	12.00	74.00	21.00
	GF	0	0	0	0	0	0	0	0	0	0
	CF	2,297,110	4,164,277	0	4,164,277	4,323,595	757,224	5,080,819	984,512	6,065,331	1,688,172
	CFE	2,160,337	698,191	0	698,191	352,228	0	352,228	0	352,228	0
	FF	0	0	0	0	0	0	0	0	0	0
(1) Executive Director's Office (A) Administration and Information Technology Vehicle Lease Payments	Total	2,295,586	2,372,285	0	2,372,285	2,372,285	6,860	2,379,145	4,408	2,383,553	35,266
	FTE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	GF	754,908	368,485	0	368,485	368,485	0	368,485	0	368,485	0
	GFE	0	0	0	0	0	0	0	0	0	0
	CF	130,000	483,727	0	483,727	483,727	6,860	490,587	4,408	494,995	35,266
	CFE	1,373,617	1,478,540	0	1,478,540	1,478,540	0	1,478,540	0	1,478,540	0
	FF	37,061	41,533	0	41,533	41,533	0	41,533	0	41,533	0
(1) Excutive Director's Office (A) Administration and Information Technology Amortization Equalization Disbursement	Total	659,938	1,078,513	0	1,078,513	1,482,030	9,997	1,492,027	13,202	1,505,229	23,199
	FTE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	GF	233,748	232,658	0	232,658	344,523	0	344,523	0	344,523	0
	GFE	0	0	0	0	0	0	0	0	0	0
	CF	82,632	262,590	0	262,590	379,066	9,997	389,063	13,202	402,265	23,199
	CFE	295,277	469,702	0	469,702	621,631	0	621,631	0	621,631	0
	FF	48,281	113,563	0	113,563	136,810	0	136,810	0	136,810	0

Schedule 13
Change Request for FY 08-09 Budget Request Cycle

Decision Item FY 08-09 ☐ **Base Reduction Item FY 08-09** ☐ **Supplemental FY 07-08** ☐ **Budget Request Amendment FY 08-09** ☑

Request Title: Additional FTE to Address OGCC's Workload and Changing Mission
Department: Natural Resources
Priority Number: 1a of 24

Dept. Approval by: **Date:**
OSPB Approval: **Date:**

	Fund	1 Prior-Year Actual FY 06-07	2 Appropriation FY 07-08	3 Supplemental Request FY 07-08	4 Total Revised Request FY 07-08	5 Base Request FY 08-09	6 Decision/ Base Reduction FY 08-09	7 November 1 Request FY 08-09	8 Budget Amendment FY 08-09	9 Total Revised Request FY 08-09	10 Change from Base (Column 5) FY 09-10
(1) Excutive Director's Office	**Total**	0	214,102	0	214,102	470,332	4,687	475,019	6,187	481,206	7,250
(A) Administration and Information Technology	**FTE**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental	**GF**	0	41,546	0	41,546	119,367	0	119,367	0	119,367	0
Amortization	**GFE**	0	0	0	0	0	0	0	0	0	0
Equalization	**CF**	0	51,042	0	51,042	120,816	4,687	125,503	6,187	131,690	7,250
Disbursement	**CFE**	0	97,855	0	97,855	192,146	0	192,146	0	192,146	0
	FF	0	23,659	0	23,659	38,003	0	38,003	0	38,003	0
( ) Long Bill Group											
Line Item Name	**Total**	2,680,439	3,165,863	0	3,165,863	3,165,863	0	3,165,863	48,000	3,213,863	0
(A) Administration and	**FTE**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Information Technology	**GF**	1,008,990	876,300	0	876,300	876,300	0	876,300	0	876,300	0
Legal Services	**GFE**	0	0	0	0	0	0	0	0	0	0
	CF	565,510	949,523	0	949,523	949,523	0	949,523	48,000	997,523	0
	CFE	1,060,613	1,291,865	0	1,291,865	1,291,865	0	1,291,865	0	1,291,865	0
	FF	45,326	48,175	0	48,175	48,175	0	48,175	0	48,175	0
( ) Long Bill Group											
Line Item Name	**Total**	857,309	957,548	0	957,548	987,330	0	987,330	86,163	1,073,493	86,163
(A) Administration and	**FTE**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Information Technology	**GF**	496,573	487,039	0	487,039	492,842	0	492,842	0	492,842	0
Leased Space	**CF**	251,524	355,538	0	355,538	372,228	0	372,228	86,163	458,391	86,163
	CFE	86,124	91,832	0	91,832	98,972	0	98,972	0	98,972	0
	FF	23,088	23,139	0	23,139	23,288	0	23,288	0	23,288	0

Letternote revised text:

Cash Fund name/number, Federal Fund Grant name: Oil and Gas Conservation and Environmental Response Fund (Fund 170)

IT Request: ☐ **Yes** ☑ **No**

Request Affects Other Departments: ☑ **Yes** ☐ **No** **If Yes, List Other Departments Here:** DPA Fleet Management and the Department of Law

CHANGE REQUEST for FY 08-09 BUDGET REQUEST CYCLE

Department:	Natural Resources
Priority Number:	1a out of 24
Change Request Title:	Additional FTE to Address OGCC's Workload and Changing Mission

SELECT ONE (click on box):

☐ Decision Item FY 08-09
☐ Base Reduction Item FY 08-09
☐ Supplemental Request FY 07-08
☒ Budget Request Amendment FY 08-09

SELECT ONE (click on box):

Supplemental or Budget Request Amendment Criterion:
☐ Not a Supplemental or Budget Request Amendment
☐ An emergency
☐ A technical error which has a substantial effect on the operation of the program
☒ New data resulting in substantial changes in funding needs
☐ Unforeseen contingency such as a significant workload change

<u>Short Summary of Request</u>: The OGCC is requesting $1,142,472 cash funds for 12.0 FTE, three State vehicles, additional lease space, and one-time additional legal services funding to enforce new rules that will be adopted by the Colorado Oil and Gas Conservation Commission, effective July 1, 2008. Funds for this request will come from the Oil and Gas Conservation and Environmental Response Fund (Fund #170).

<u>Background and Appropriation History</u>: The OGCC's Program Cost line funds the OGCC's personal services and operating expenses, including 53.0 FTE, commission hearing expenses, travel expenses, vehicle mileage, information technology, and general office overhead. The employees funded through this line item are involved in field inspections, complaint response, enforcement, permitting, regulatory report reviews, environmental studies, mitigation of impacts caused by oil and gas activity, management of data related to the approximately 33,000 active and 40,000 inactive wells, and general administration.

To address the significant increase in oil and gas industry activity, this long bill line item has increased from $2,732,859 and 33.0 FTE in FY 2004-05 to $4,853,967 and 53.0 FTE in FY 2007-08. Each incremental increase to the agency's budget addressed the anticipated workload for the budget request year, but not far beyond, due to the volatility of the oil and gas industry. The FY 2007-08 request was driven by workload metrics forecasted under the existing statutory authority of the OGCC in FY 2006-07.

The landscape of the oil and gas regulatory environment has changed rapidly, however, due to the enactment of HB 07-1341 and HB 07-1298, the later of which directs the OGCC to "minimize adverse impacts to wildlife resources affected by oil and gas operations" through various actions, including developing rules by July 1, 2008 that address:

- "developing a timely and efficient consultation process with the Division of Wildlife governing notification and consultation on minimizing adverse impacts, and other issues relating to wildlife resources";
- "encouraging operators to utilize comprehensive drilling plans and geographic area analysis strategies to provide for orderly development of oil and gas fields"; and
- "minimizing surface disturbance and fragmentation in important wildlife habitat by incorporating appropriate best management practices" in orders, rules, and approvals.

Similarly, HB 07-1341 requires the OGCC to promulgate rules no later than July 1, 2008, in consultation with the Colorado Department of Public Health and Environment (CDPHE), "to protect the health, safety, and welfare of the general public in the conduct of oil and gas operations," and to "provide a timely and efficient procedure in which the [CDPHE] has an opportunity to provide comments during the [OGCC]'s decision-making process."

After several months of consultation with DOW, CDPHE, federal agencies, industry, and environmental, wildlife, agricultural, and local government groups, the OGCC rolled out an initial pre-draft rulemaking proposal on November 27, 2007 and posted it to the agency's website on December 7, 2007 (see Attachment A). Comments from the public on this proposal were accepted through December 18, 2007. To generate additional input, the OGCC, DOW, and CDPHE will be scheduling a series of stakeholder work groups to address various parts of the proposal. It is anticipated that these meetings will begin in early January 2008 and run through the middle of February 2008. The results will be used to prepare the draft rules, which the agency expects to publish in late March 2008. The draft rules, in turn, will be subject to additional public comment and rulemaking hearings before they are adopted. In addition, it is anticipated that five public meetings will be held in various oil and gas producing areas of the state to improve the public's ability to offer comments/suggestions and to voice their concerns.

The budgetary impact of the bills was not well understood during the legislative session or in time to include in the November 1, 2007 budget request. The Department's fiscal note for HB 07-1298, however, indicated that if the process of consultation with the Division of Wildlife (DOW) resulted in a major revision of OGCC regulations it would likely result in very prescriptive permitting and enforcement requirements that would call for a major modification in information technology infrastructure along with increased permitting and compliance resources.

Even though no rules have actually been promulgated by the date of this budget amendment, and there is a long process ahead, the initial pre-draft rulemaking proposal indicates that substantial changes to the regulatory oversight of the oil and gas industry may be on the horizon. Without additional staff, however, none of the proposed rules can be implemented. The agency has always maintained lean staffing levels and used well documented workload metrics, such as the number of active wells (Figure 1), Applications for Permits to Drill (APD's) (Figure 2), and active drilling rigs (Figure 3) to justify new staff. The agency is now faced with:

- historic highs in all of these metrics;
- the need to establish new procedures that would improve the efficiency and effectiveness of the agency, regardless of any new rules that may or may not be promulgated; and,

- the need to be prepared for potential new rules that the agency will be required to implement on July 1, 2008.

Given that these issues are moving targets until the rules are finalized, the Department has asked for the absolute minimum amount of staffing required to address them. This skeletal crew is not expected to be the complete solution, but rather the first step until new rules are promulgated, new processes are put in place, and the necessary resources are identified. Some of the concepts discussed in the initial pre-draft rulemaking proposal, such as the requirement to involve adjacent landowners in on-site inspections, have not been addressed in this request. Additional FTE in FY 2009-10 may be required to efficiently enforce new rules at the level expected by the public, the governor, the general assembly, local governments, the oil and gas industry, and environmental and wildlife groups.

The three figures below are direct indicators of the OGCC's workload. The number of active wells, permit applications, and active drilling rigs has clearly outpaced the number of FTE.

Figure 1

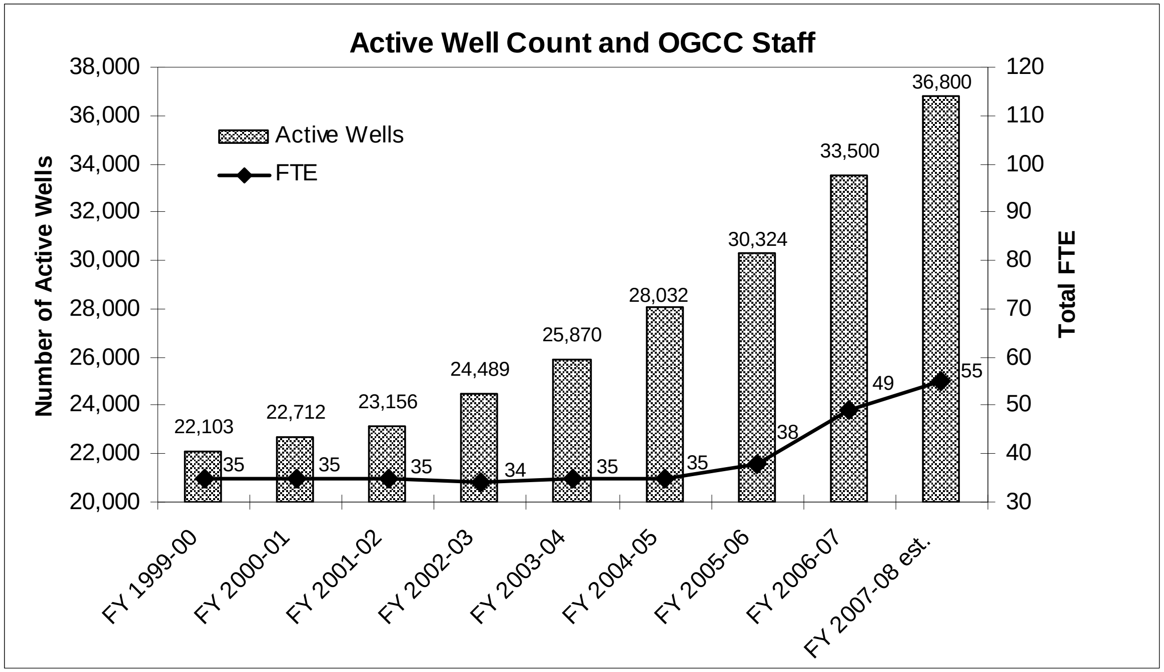
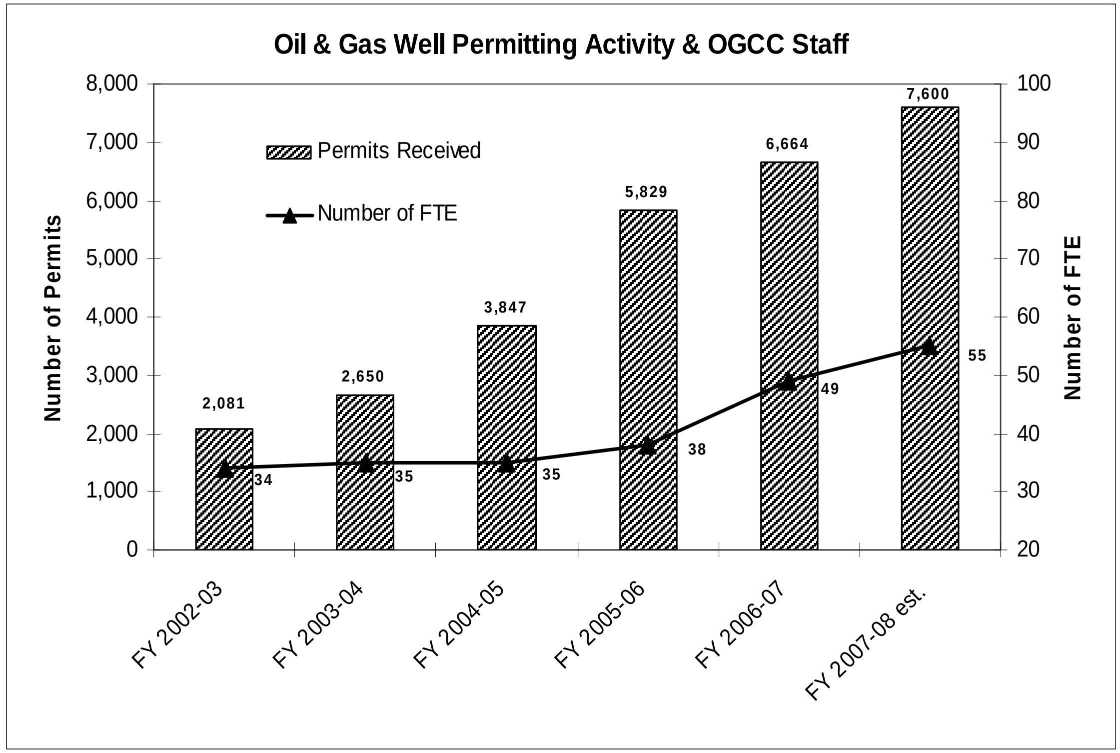


Figure 2



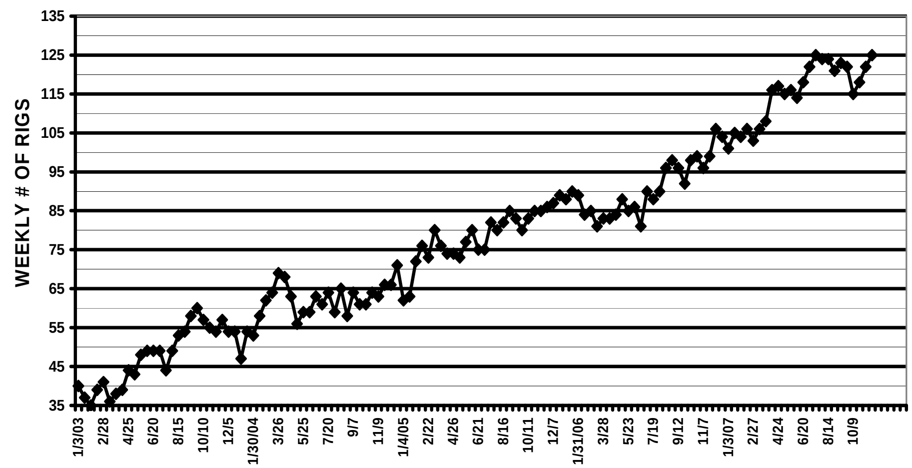
As can be seen on the above chart, the ratio of permits to FTE has increased from 61 permits per FTE in FY 2002-03 to 138 in FY 2007-08. Even though staffing levels have increased nearly 62 percent over that time frame the agency is still experiencing a severe shortfall of resources needed to regulate the industry in a balanced manner that includes the protection of public health, safety, and welfare, in addition to the environment and wildlife.

As shown below, the number of active drilling rigs in the state has increased from an average of 41 in the second half of FY 03 to 122 during the first 5 months of FY 08. This metric alone represents a 194% increase in "on-the-ground" industry activity over a 4 ½ year period. This unprecedented level of activity, which is not expected to decline in the foreseeable future, has impacted every aspect of the agency.

Figure 3

TOTAL DRILLING RIGS RUNNING IN COLORADO EVERY OTHER WEEK IN 2003-2007

(based on data from: PI/Dwights Drilling Wire through 4/30/03, Anderson Reports Weekly Rig Status Report after 4/30/03)



General Description of Request: House Bills 07-1341 and 07-1298 appear to be driving the most comprehensive revision of the OGCC's rules and its organizational structure since 1994. At the heart of the initial pre-draft rulemaking proposal is a new process in which an operator would submit a Form 34, Intent to Locate an Oil and Gas Facility, and obtain Director's approval before it can commence construction of a location for an oil and gas operation. Public notice of the Form 34 application would be accomplished by postings to the OGCC website, giving the public a 30-day period in which they may submit comments, which would need to be reviewed by administrative staff to ensure the state does not publish offensive, racist, or inflammatory comments. Technical staff must also review the comments to evaluate their merit and determine whether or not OGCC rules adequately address the issues, or if conditions of approval should be added to the permit. In certain circumstances, applications for a Form 34 permit would trigger consultation between the operator and CDOW and/or CDPHE.

A "location" would be a definable area in which an operator intends to disturb land surface in order to locate an oil and gas facility. An "oil and gas facility" would mean all equipment used or installed at a location for exploration, production, and/or processing oil or natural gas, including a site for drilling a well or conducting drilling operations, access roads, tanks, compressors, infield oil, gas, and water pipelines, and reclamation activities. Currently, the OGCC does not have a process for permitting and tracking the locations and acres of surface disturbance caused by oil and gas facilities other than the wells. The ancillary facilities, however, need to be tracked if cumulative impacts are to be addressed. The Form 34 permit process would provide an effective and efficient system for addressing the site-specific impacts to public welfare and wildlife from oil and gas facilities in Colorado. The benefits of such a process would include:

- allowing operators to address the impacts on public welfare and wildlife from multiple wells at a single location;
- enabling the OGCC to review and address the effects of ancillary oil and gas facilities;
- focusing the involvement of CDOW and CDPHE on issues of particular importance to those agencies;
- incorporating early protections for surface owners;
- increasing transparency and opportunities for public input; and
- expediting the issuance of drilling and waste management permits.

To support the proposed Form 34 process, a post-construction facilities inventory (Form 35), and the continuously growing industry activity, the OGCC needs to reorganize and expand its staff in FY 2008-09 and potentially again in FY 2009-10 after the rules have been promulgated and the impacts on workload are fully defined. Attachment B is the agency's FY 2007-08 organization chart, whereas Attachment C is the proposed FY 2008-09 organization. Shown in shaded squares on the latter are the 9.0 environmental FTE already requested in the Department of Natural Resources' Decision Item #1. The Environmental Protection Specialist II's described in that decision item will be the core of the new Surface Locations group in the environmental section. The already requested Environmental Specialists I's, referred to as environmental inspectors, will join the proposed new Compliance Section, which will include all existing field inspectors. The positions in cross-hatched ovals, and listed below, are requested through this budget amendment and are required for either supervision or support of these new groups and other groups in the agency.

Requested positions, listed as they appear from left to right in the proposed organization chart (Attachment C):

Working Title	State Job Classification	Number of FTE
Application Programmer	Information Technology Professional II	1.0
Network Administrator	Information Technology Professional II	1.0

GIS Administrator	Physical Science Research/Scientist III	1.0
Permit/Compliance Tech	Engineering/Physical Science Tech II	2.0
Bond Administrator	Program Assistant I	1.0
NW Area Engineer	Professional Engineer I	1.0
Surface Location Supervisor	Environmental Protection Specialist III	1.0
Compliance Manager	Environmental Protection Specialist IV	1.0
Compliance Supervisors	Physical Science Tech III	3.0
Total Requested FTE		12.0

Position Descriptions

Application Programmer:
The new business processes, driven by House Bills 07-1298 and 07-1341, will require the development and maintenance of a supporting computer system to ensure the efficient use of state resources and timely processing of forms.

The new applications that are being designed for these purposes are expected to double the information technology (IT) work load of the agency. Currently, the OGCC has one application programmer, a new position in FY 2007-08, to support the Colorado Oil and Gas Information System (COGIS). That programmer is working on a five-year backlog of projects. Adding another complex system without any new FTE would seriously degrade the IT staff's ability to adequately support the staff. Full-time employees that understand the code and are available to work on the system, make routine modifications/enhancements, and answer questions, as needed, are the most cost effective and efficient means of keeping essential systems operating on a daily basis. Table 1 lists known projects with which the requested application programmer would be tasked. More are expected to be identified as the rulemaking process continues.

Table 1

Project Title	**Reason**	**Estimated Hours**
Cumulative Impact Measurement System	This project will allow the OGCC and other state agencies to track the impacts of oil and gas development on the environment, a requirement of HB 07-1298 and 07-1341. Information will be added to the system over the life of the oil and gas facilities and will be used by state and other public agencies to assess cumulative impacts and ways to mitigate them.	3,500 hours

Reclamation and Remediation Tracking System	A major component of the new rules is expected to be the operators' environmental evaluation and plan for reclamation of sites involved in the oil and gas operations. To be able to fully implement the new rules, ensure compliance, and enforce against instances of non-compliance, a system will need to be created that maintains a database with all the relevant information for each location that is permitted under the new rules. Application approval process, rule compliance, and enforcement must be available to all the agencies involved.	1,800 hours
Water Quality Database	This project would allow all historical and future water quality data to be analyzed by the entire staff through a common computer interface. Additionally, an Internet application would make the water quality data available to the public through the OGCC web site by custom query parameters. The ability to have this information available to the staff and others outside the agency without having to make special requests will provide a long term benefit by eliminating the requirement to generate custom reports for interested parties.	1,500 hours
Directional Drilling Information	The use of directional drilling to minimize impacts to the environment by sharing a common well site for multiple wells is encouraged by the OGCC whenever practicable. This project will enable the industry to submit directional survey data electronically; so that it can be used by the agency's online mapping system and other reporting tools. Staff and the public can analyze the data to evaluate and confirm that proposed and existing well bores are in compliance with existing rules and commission orders.	1,000 hours
Upgrade to COGIS Online Map System	The current software used by field staff to display their maps has been phased out by the vendor, and will no longer be supported after 2009. The IT group must review and select a replacement. The current system is deployed on laptops because cell phone access is limited, thus an Internet based application is not an option. If moving to the new application requires significant programming, planning and funding must take place in FY 2008-09.	850 hours
Public Comment WEB Site	Form 34 applications will be posted on the OGCC website and be subject to a 30 day public comment period. An application that can accept the comments, without posting them prior to OGCC review, needs to be developed. The review is necessary to ensure that the state is not publishing any comments that are offensive, racist, or in any other way placing the state in a position of fostering hate. In addition, the comments must be reviewed by the technical staff, primarily environmental, but with engineering review as needed, to evaluate the merit of the comment and to determine whether or not OGCC rules adequately address the issues or if conditions of approval should be added to the permit. This project would create an application to automate the process of review as much as possible, in addition to tracking the individual who approved or rejected the comment.	?

Network Administrator:

The technical support needs of the OGCC's existing 55 FTE, which includes 16 field-based employees, have exceeded the capacity of the agency's one network administrator. This FTE provides support for all hardware, including desktop computers, laptops, servers, printers, communications for field employees, Geographic Positioning System (GPS) units, digital cameras, noise meters, and other digital devices required by staff. An additional 20.0 FTE (the sum of this request plus DNR's Decision Item #1, minus this position) would cause serious delays in hardware maintenance without additional support.

By creating an IT Professional II position to lead the network administration "team", a coordinated effort would be made to ensure problems are prioritized appropriately so that field staff always gets the help they need to optimize performance. The network administrator currently receives a weekly average of 30 calls for assistance, 11 of which take more than one day to resolve. The majority of those more complex problems requires extensive research and often requires the network administrator to spend significant hands-on-time with the problem computer. Without an additional network administrator to support a 42% increase in staff, equipment downtime would be inevitable.

This team will also be responsible for building new workstations to the specifications required by the new positions, testing the machines to ensure they are field ready, and preparing all equipment for shipment when necessary. In addition to supporting the hardware needs of the agency, the requested FTE would develop backup procedures for the agency's servers and act as the OGCC's security officer to ensure the State's policies are being met.

Finally, the proposed new OGCC forms 34 and 35 would nearly double the data elements tracked by the agency. This position would be cross-trained in database management to assist in maintaining the integrity of the Colorado Oil and Gas Information System. The current database manager, who also serves as the permit manager, has been overloaded for several years with the demands of both jobs. For succession planning it is becoming essential that institutional knowledge of COGIS is transferred to a qualified employee to the greatest extent possible.

Geographic Information System (GIS) Administrator:

Recent meetings between the OGCC, CDOW, and CDPHE have identified GIS technology as critical to the success of coordination efforts between these agencies, industry, and local governments, as required by House Bills 07-1298 and 07-1341. The OGCC currently employs one GIS administrator (classified as a Physical Science Research/Scientist II) to manage and continuously update over 130 map layers that contain information such as oil and gas well locations, OGCC spacing orders, soil surveys, water wells, color aerial photos, topographic maps, statewide land ownership, federal mineral leases, and environmental data. The system also hosts 18 Bureau of Land Management (BLM) layers and five State Land Board layers. It will soon be hosting CDPHE and DOW layers. As it is the only source of real-time oil and gas data in the state, the OGCC's GIS data system will be the primary tool for interagency communication and coordination, as required by House Bills 07-1341 and 07-1298.

Due to the high level of industry activity over the last several years, the agency's GIS administrator currently has a one year backlog of projects that includes the development of an oil and gas field mapping program, a directional drilling application, and spacing order mapping. As a result, this FTE cannot absorb additional, ongoing tasks. The requested GIS Administrator would take the essential next step and perform complex analyses of oil and gas operational and environmental data to support OGCC, CDOW, and CDPHE management decisions. This requires a unique combination of technical background and skills, such as a thorough knowledge of oil and gas exploration/development data, environmental data, petroleum geology, hydrogeology, and regulatory frameworks, in addition to the ability to incorporate these data into meaningful GIS applications.

The requested position will also testify at OGCC hearings regarding analysis of operational and/or environmental technical data, conduct outreach training seminars for industry, other agencies, and the general public on the OGCC's GIS data system, and supervise the existing GIS position.

***Permit/Compliance Technicians*:**

The proposed Form 34 will change the process for permitting new wells, from a one-step process, the Application for Permit to Drill, to a two-step process. The first step in the two-step process is the new Form 34, which permits the surface disturbance of the well site and ancillary facilities. The second step is a modified APD, which permits the down-hole construction of the well. Although the agency's workload will be impacted by the additional form and the follow-up report, Form 35, the new process will track oil and gas impacts more completely than the current APD, which was originally designed for the one-well-per-location concept. About one half of the wells permitted in the state in CY 2006 were drilled directionally from a common pad used for multiple wells. This drilling technique has significantly reduced surface impacts, but the OGCC has had no mechanism for tracking the number and size of well pads and ancillary facilities, as it does for the number of well bores. Therefore, the cumulative impacts of resource development cannot be determined.

Calculating the workload impact of the new Form 34 and the follow-up form 35 is difficult, given both are in concept form at the time of this writing and have not been fully developed. However, Table 1 below, which is staff's comparison of the existing permit process with the draft Form 34 process, indicates that the existing APD and follow-up regulatory reports will require 16,163 man hours to process an expected 8,360 APD's in FY 2008-09, whereas the proposed modified APD and new Form 35 will require a total of 20,482 man hours. The difference, 4,319 man hours, is approximately equal to 2.0 FTE. The calculations are based on the assumption that for every 10 APD's, approximately 7 Form 34s will be submitted for well pads and ancillary facilities, such as gathering lines, centralized pits, storage facilities, gas plants, compressors, and dehydrator units.

Table 2

Permit/Compliance Technicians' Tasks	**Existing**		**Proposed**	
	APD		**Modified APD**	**Form 34**

	Minutes Per Task	**Number of Tasks (equates to Expected # of APDs)**	**Total Number of Hours Annually**	**Minutes Per Task**	**Number of Tasks (equates to Expected # of APDs)**	**Total Number of Hours Annually**	**Minutes Per Task**	**Number of Tasks (equates to Expected # of Form 34s)**	**Total Number of Hours Annually**
Pre-process review of permit for completeness of application	15	8,360	2,090	5	8,360	697	10	5,852	975
Validation of location and identification	3	8,360	418	3	8,360	418	3	5,852	293
Compliance review for financial assurance	2	8,360	279	0	8,360	0	2	5,852	195
Review of notification and consultation requirements	10	8,360	1,393	0	8,360	0	15	5,852	1,463
Compliance review of safety setbacks from existing geographic features	20	8,360	2,787	0	8,360	0	30	5,852	2,926
Compliance review of well location and density	20	8,360	2,787	30	8,360	4,180	0	5,852	0
Tracking and approval	10	8,360	1,393	10	8,360	1,393	15	5,852	1,463
Completion Documentation	12	25,080	5,016	12	25,080	5,016	15	5,852	1,463
Total Est. Processing Time for Permit/Compliance Staff - Using Existing APD			16,163						
Total Est. Processing Time for Permit/Compliance Staff - Using the Proposed Modified APD and Form 34						11,704			8,778

It should be noted that there are significant differences in the responsibilities of the permit/compliance technicians requested here, the Environmental Protection Specialist II's (EPS II's), which are requested in the Department of Natural Resources' Decision Item #1 for environmental reviews of drilling permits, and the five contractors requested in Budget Amendment 6a. Under the proposed rules, the EPS II's will conduct environmental reviews of Form 34's much like the engineers review and approve APD's. The permit/compliance technicians will perform the steps listed above, in addition to facilitating the reviews by the environmental and engineering experts.

While the need for permit/compliance technicians is driven by the proposed new rules, the contractors requested for the permit section in Budget Amendment 6a will address the backlog of APD's and other follow-up regulatory reports that are accumulating in FY 2007-08. Without the contractors, the backlog would continue to grow in FY 2008-09, until the requested permit/compliance technicians are fully trained and the proposed new permitting process is running smoothly.

Bond Administrator:

OGCC statutes and rules require operators to file and maintain adequate financial assurance for certain operations until the site is properly closed, any environmental damage is remediated, and the site is returned to its original condition as near as practicable. Multiple instruments, such as cash bonds, insurance bonds, certificate of deposits, money market accounts, and letters of credit, can be used as financial assurance. As of November 2007, the OGCC's one "Bond Administrator" was tracking 715 operators and 1,045 financial assurance instruments worth over $26 million. About 230 of those are monetary instruments that require an annual validation with the financial institution.

As the level of industry activity has increased over the last five years, so has the Bond Administrator's workload. Temporary help that equates to about 0.3 FTE has been used since July 2006 to assist with bond releases and other tasks. Although the agency did not keep a statistical record of the backlog of bond release requests until recently, the current backlog is 147 bonds, some of which are for one well, while others are for hundreds. Each require coordination with the operator, the financial institution, field inspectors, and other staff members to ensure the operation for which the financial assurance was required is properly completed and all required regulatory reports have been submitted. The multi-month to multi-year delays for bond releases are directly related to the heavy workload of OGCC field and office staff, but they exacerbate the problems of the Bond

Administrator, who must monitor the bond releases for longer periods of time and field frequent calls from operators wanting progress reports on their requests.

Examples of other workload increases include new operator registrations, change of operator notifications, and bond replacements. The Bond Administrator registered 133 new operators in FY 2006-07, as opposed to 62 in FY 1999-00. Over 7,000 wells changed hands in FY 2006-07, up from about 1,800 in FY 1999-00. Every well must be accounted for in these transactions to protect the state from orphaned wells, which would ultimately become the OGCC's responsibility to plug and reclaim if the owner cannot be identified. Finally, the number of bonds that were replaced by operators with new bonds grew from 44 in FY 1999-00 to 149 in FY 2006-07.

The workload increases have been absorbed, to some extent, by the Bond Administrator and temporary help over the last several years, but the volume has grown beyond the agency's capacity under existing rules. The draft rules associated with 2007 legislation contemplate adding financial assurance requirements to oil and gas facilities that did not previously require bonding. These new requirements, without additional FTE, would significantly delay all functions performed by this section, causing much frustration for the industry. The sheer magnitude of the moneys entrusted to the state as performance bonds justifies the need for a second FTE in the bonding section of the OGCC. Requesting a third FTE was seriously considered, but the agency decided to wait until the rules were promulgated before making that potential request.

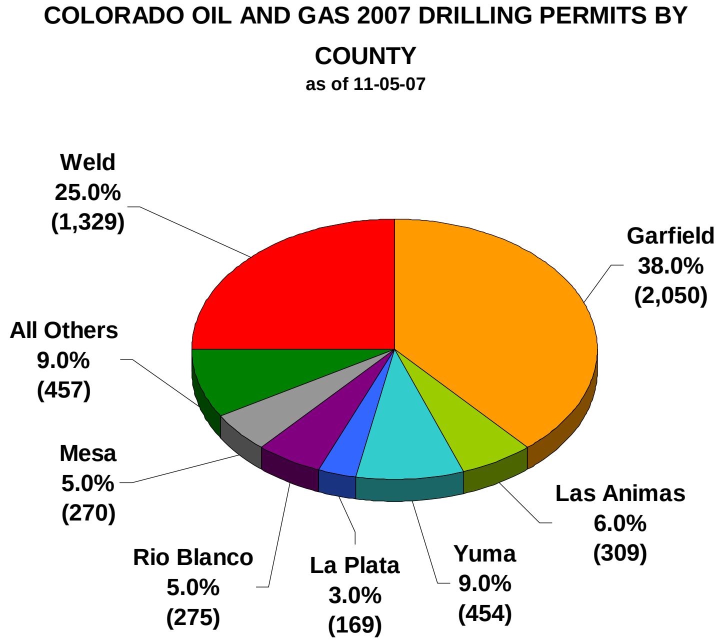
NW Area Engineer:

The OGCC engineering staff regulates oil and gas drilling activities in Colorado through the review and approval of Applications for Permits to Drill (APD's) and regulatory reports filed after a well is drilled. Currently, about 48% of the drilling activity in the state is occurring in northwest Colorado (Figure 6). This high level of activity not only increases the number of drilling permits requiring review and approval but also increases the number of subsequent reports to be reviewed and approved by the engineering staff as individual wells proceed through the drilling, completion, and production phases.

The engineering review and approval of APD's has been a high priority but is not keeping pace with the submittal of new permit requests. Review of follow-up regulatory reports, such as completion reports, has fallen far behind. Timely processing of these reports allows OGCC staff to discover and resolve problems that may have occurred during the drilling or completion phase of an oil and gas well. Early detection of poor cement bonding, poor cement circulation, and perforations placed too close to the top of cement can minimize environmental damage caused by high pressure gas leaking outside of the production casing. The accelerated pace of activity has delayed the review and approval of completion reports, sundry notices, geophysical logs, and other reports that update well information, which are currently running four to five months behind submittal dates.

To avoid continuing these long delays the OGCC recommends the addition of one Professional Engineer to the Rifle office. This position would focus on the approval of regulatory forms, the review of well completions, and other well-related work. The job duties require a Professional Engineer with petroleum engineering experience to provide the level of technical review needed.

Figure 6



Surface Location Supervisor:

A new technical group, the Surface Location Group, will be created for reviewing the Form 34, and will include a group supervisor and four environmental protection specialists (EPS II's). The new group will be contained in the environmental section and managed by the Environmental Manager. The four EPS II's that were already requested in the Department of Natural Resources' Decision Item #1 for FY 2008-09 will be the core of this group. As described in Decision Item #1, the four EPS II's were going to conduct more thorough reviews of potential environmental issues associated with oil and gas wells, such as proximity to and type of water resources, geologic structures, surface deposits and soils, vegetation, and wildlife habitat as part of the Application for Permit to Drill, Form 2 process. This type of technical review will still be performed by these four EPS II's, but as part of the Form 34 permit application review process. For this budget amendment, only the group supervisor position is being requested.

The requested Surface Location Supervisor (EPS III) will supervise the four EPS II's and take the lead in establishing the new process for reviewing and approving the Form 34. The supervisor will work closely with the information group to:

- monitor the success of electronic submission by operators and subsequent review by the EPS II's;
- identify and prioritize changes needed to ensure an effective and efficient process; and
- monitor the process to identify and implement improvements.

The supervisor will also be responsible for establishing bench marks for determining the success of the process and for ensuring the EPS II's are properly cross trained and reviewing Form 34s consistently. This supervisor will coordinate with the engineering and environmental sections, as these groups review and approve other types of OGCC permits including APDs and those for waste management facilities. When a Form 34 requires engineering review, the supervisor will coordinate with the engineering supervisors to identify the appropriate in-house engineer to conduct the review. The supervisor will also coordinate the consultation process with CDOW and CDPHE personnel.

In response to HB 07-1298 requirements, oil and gas operators will be encouraged to create comprehensive development plans (CDP) that will provide OGCC, CDOW, CDPHE, and other stakeholders with a broader understanding of the total number of wells that will be drilled, the associated facilities that will be constructed over larger areas, and methods for avoiding, minimizing, or mitigating negative impacts from all of these activities. The large scale information provided in the CDP and the site specific information provided in the Form 34 will be used by the Surface Location group to develop conditions of approval to address potential impacts to public health, safety, welfare, and the environment including wildlife resources that are not completely addressed by OGCC rules. The supervisor will assist in the development of conditions of approval and ensure that the EPS II's consistently apply them, when appropriate. The supervisor will also take the lead in working with the information group to develop a process for incorporating information contained in these plans into the OGCC master relational database (MRDB).

Compliance Section

The OGCC's current organizational structure (Attachment B) shows the field inspectors (Engineering/Physical Science Technician II's) in the engineering section supervised by engineers. In addition to overseeing the inspection program, the engineers review and approve APD's, completion reports, Underground Injection Control applications, and other well-related paperwork, all of which continue to increase in volume. Due to intense competition with industry for experienced engineers the OGCC has been required to hire engineers with little or no experience, requiring the more experienced engineers to spend an extraordinary number hours training the new hires. Removing the field inspectors from the engineering group will keep the engineers focused on the technical review of well bore construction, the agency's first line of defense against environmental damage, and the essential training of new engineers.

Creating a new "Compliance Section" that will include the field inspectors and the new Environmental Inspectors (Environmental Protection Specialist I's), previously requested in DNR's Decision Item #1, will provide better focus on inspections, ensuring compliance with OGCC rules, permit requirements, and conditions of approval that have been placed on permits. Because the staff members of this new group exist, or have already been requested through Decision Item #1, this budget amendment includes only the section manager position and three compliance supervisor positions.

Compliance Manager:
The Compliance Manager, an Environmental Protection Specialist IV, will be responsible for building a cohesive team of well trained and motivated field inspectors. The manager will work directly with the Compliance Supervisors, the engineering manager, and environmental manager to establish priorities among the variety of inspection types, such as drilling, cementing, plugging and abandonment, bond releases, mechanical integrity tests, UIC, reclamation, stormwater, and complaint, to optimize the use of inspectors' time. The manager will also be responsible for:

- developing a flexible system that will respond to changes in field operations and priorities, emphasize follow-up to ensure violations are corrected within the required period of time, pursue additional enforcement if necessary, and establish meaningful measures to evaluate the effectiveness of the compliance section;
- ensuring that compliance staff is kept current on evolving oil and gas field technologies and processes by providing adequate training opportunities; and
- coordinating with the engineering and environmental sections to ensure adequate support for their inspections needs.

Compliance Supervisors (3.0 FTE) located in Northwest, Northeast, and Southern Colorado:
The proposed Compliance Supervisors, classified as Engineering/Physical Sciences Technician III's, will be required to have extensive experience in oil and gas field operations and environmental compliance. They will be responsible for ensuring inspectors are properly trained and have the necessary equipment, including adequate safety gear, to conduct the required inspections. Such training would include:

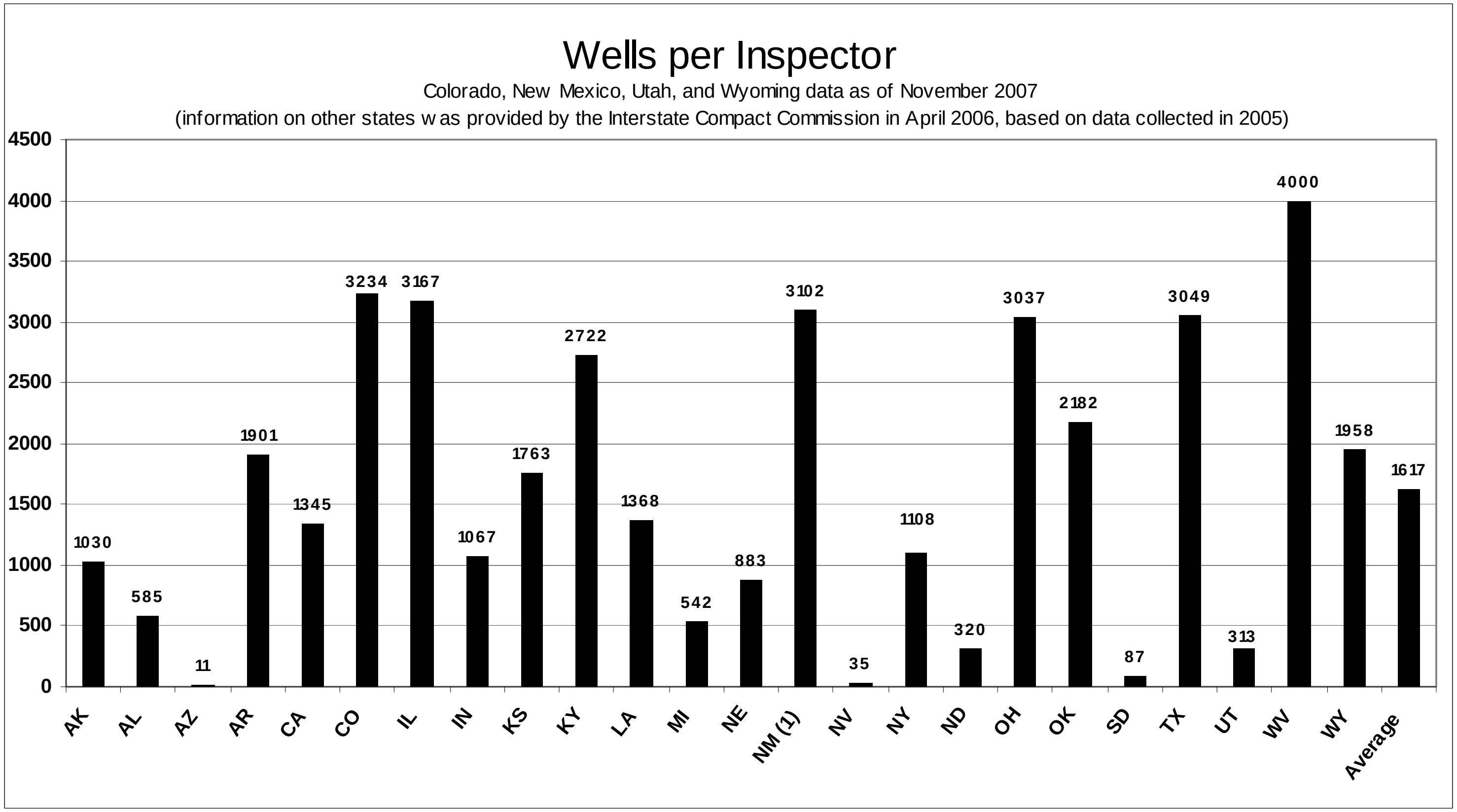
- oil and gas exploration and production field operations;
- safety;
- monitoring equipment, such as noise meters, odor meters, and explosimeters;

- defensive driving; and
- proper use of OGCC's electronic forms and GIS system.

They will be responsible for ensuring all inspectors consistently enforce OGCC rules and providing recommendations to the manager on needed changes that would improve the quality and efficiency of inspections. In addition to their supervisory duties, the compliance supervisors will be responsible for conducting routine field inspections and taking the lead in inspections and field consultation that might be requested by land owners, CDOW, CDPHE, or the local government designee, as part of the Form 34 permit process.

Figure 7 below indicates that the number of active wells per inspector in Colorado (3,234) is significantly higher than the reported nation-wide average of 1,617. Although the number of active wells continues to increase, the three compliance supervisors, in addition to the four environmental inspectors included in the November 1, 2007 request, will bring Colorado closer to the national average. It should be noted, however, that a high level nation-wide comparison of wells per inspector can be overly simplistic. Each state has its own set of rules, some of which are more complex and time-consuming to enforce than others. The terrain and the density of wells also play major roles in the number of wells an inspector can oversee.

Figure 7



Footnote: Wells located on surfaces owned by the Federal Government or the Southern Ute Indian Tribe are not included in the figures. Although they impact nearly every aspect of the OGCC's workload, such as reviewing permit applications, maintaining well files, collecting production data, and processing mill levy payments, the agency does not typically conduct well inspections on these properties.

Legal Services

Combined, HB 07-1341, HB 07-1298, and HB 07-1180 increased the number of members on the Commission from seven to nine and require the OGCC to undertake three separate rulemakings in FY 2007-08 to implement new statutory requirements for industry operations that specifically take into consideration wildlife and environmental concerns. In addition, the OGCC will now be required to consult and coordinate with the CDPHE and the CDOW on applications to drill.

Legal services will be necessary in advance of the rulemaking to advise the Commission and staff on legal issues, during the rulemaking hearing itself, and after the rulemaking, in hearings that apply the new regulations to oil and gas operators. In addition, there may be litigation filed in conjunction with the new regulations. The advice, counsel and representation in any litigation necessary after the OGCC promulgates the regulations will occur in FY 2008-09. For this reason, the request for legal services is on-time only for FY 2008-09.

The need for post-rulemaking advice, counsel, and representation will be in addition to the regular legal service requirements of the OGCC, which include ongoing litigations, representation at OGCC's administrative hearings, daily advice and counsel. Presently, the OGCC has 1.13 FTE assigned to it for legal services. This FTE allocation must cover the hours of the attorney in addition to the legal assistant help required by the attorney and supervision of the attorney's work by the First Assistant, including review of major memos and briefs, as well as consultation on issues.

In four of the last seven years, DNR has internally reallocated legal funding to cover the needs of the OGCC. However, with the above described rulemakings and the regular legal services needs of the OGCC, it is anticipated that additional funds for legal expenses will be necessary in FY 2008-09. Although difficult to project, the OGCC estimates it will need an additional .37 FTE, for a total allocation of 1.5 FTE. The additional .37 FTE equates to about 665 hours, or approximately $48,000 (using the FY 2007-08 blended rate).

Lease Space

The Denver office, located in The Chancery Building at 1120 Lincoln Street, contains 11,945 square feet and is large enough to house the 39 existing Denver-based employees and two of the five Denver-based employees that were included in the Department of Natural Resources' Decision Item #1. Additional space will be needed to accommodate the eight new Denver-based employees included in this request, as well as three employees included in Decision Item #1, for a total of 11 Denver-based employees. The three requested Compliance Supervisors will be located in home-based offices and, therefore, will not require office space in Denver.

The Chancery Building currently has several vacant leases, ranging between 4,103 and 5,020 square feet. The 4,103 square foot lease on the tenth floor would be large enough to accommodate the new employees and the OGCC's continuously growing needs for file space. At an estimated rate of $21 per square foot, the estimated lease cost associated with this request is $86,163. It should be noted, however, that there is no guarantee that this space will be available at the completion of the budget process. Adjustments to the Department's lease space line item may be needed when actual costs are known.

Consequences if Not Funded:

One of the highest priorities of the General Assembly and the Governor during the 2007 legislative session was to reduce impacts to public health, the environment, and wildlife resources from oil and gas development. Not funding this request in FY 2008-09 will severely limit the level of implementation and enforcement of new rules required by House Bills 07-1298 and 07-1341. Meaningful improvements to the regulatory oversight of the oil and gas industry, which was expected by the General Assembly, the Governor, local government, and the public when the legislation was passed, will not occur. Additionally, insufficient staff will significantly delay the oil and gas well permitting process, as resources are spread thinly over an expanded set of responsibilities to ensure development proceeds in a balanced manner.

Calculations for Request:

Summary of Request FY 08-09	**Total Funds**	**General Fund**	**Cash Funds (Fund 170)**	**Cash Funds Exempt**	**Federal Funds**	**FTE**
Total Request	$1,142,472	0	$1,142,472	0	0	12.0
Program Costs	$984,512	0	$984,512	0	0	12.0
Executive Directors Office Vehicle Lease Payments	$4,408	0	$4,408	0	0	0.0
Executive Directors Office Amortization Equalization Disbursement	$13,202	0	$13,202	0	0	0.0
Executive Directors Office Supplemental Amortization Equalization Disbursement	$6,187	0	$6,187	0	0	0.0
Executive Directors Office Legal Services	$48,000	0	$48,000	0	0	0.0
Executive Directors Office Leased Space	$86,163	0	$86,163	0	0	0.0

Summary of Request FY 09-10	**Total Funds**	**General Fund**	**Cash Funds (Fund 170)**	**Cash Funds Exempt**	**Federal Funds**	**FTE**
Total Request	$1,070,596	0	$1,070,596	0	0	12.0
Program Costs	$953,880	0	$953,880	0	0	12.0
Executive Directors Office Vehicle Lease Payments	$13,225	0	$13,225	0	0	0.0
Executive Directors Office Amortization Equalization Disbursement	$13,202	0	$13,202	0	0	0.0
Executive Directors Office Supplemental Amortization Equalization Disbursement	$4,126	0	$4,126	0	0	0.0
Executive Directors Office Legal Services	$0	0	$0	0	0	0.0
Executive Directors Office Leased Space	$86,163	0	$86,163	0	0	0.0

Assumptions for Calculations:

- FTEs are employed 12 months in fiscal years 2008-09 and 2009-10.

- The requested GIS Administrator, Permit/Compliance Technicians, Northwest Area Engineer, Location (Form 34) Supervisor, Compliance Manager, and Compliance Supervisors and are hired at 30% above range minimum. All other positions are hired at range minimum. These estimates are based on the salary requirements of recently hired employees with environmental, geological, and engineering experience. Historically, state salaries for these disciplines have been low compared to oil and gas industry salaries, but the wage gap has grown significantly over the last five years. The nation-wide shortage of qualified oil and gas personnel drove the average salary for geological personnel, with 3 to 5 years experience, to $89,600 in 2006, a 33% increase over 2001 salaries. These figures are based on the annual salary survey published by the American Association of Petroleum Geologists (AAPG) in April 2007. The OGCC's minimum requirement for Physical Science Research/Scientist III's, EPS III's, and EPS IV's is 10 to 14 years of experience. That level of experience, as reported by AAPG, is earning an average annual salary of $111,500. Environmental protection specialists and research scientists hired by the OGCC are qualified to work as geologists, or in similarly compensated environmental positions, in the oil and gas industry.

  According to the Society of Petroleum Engineers' (SPE) 2007 salary survey, the average base salary for engineers with 0 to 10 years of experience is $92,259, or 40% above the State's range minimum. The OGCC has not been able to hire any engineers with relevant industry experience within the last several years. All recently hired engineers have needed extensive training.

  At the requested annual starting salaries of $89,747, $59,155, $85,472, $89,747, $101,166, and $65,208 for the GIS Administrator, Permit/Compliance Technicians, Northwest Area Engineer, Location Supervisor, Compliance Manager, and Compliance Supervisors, respectively, this decision item does not attempt to match industry salaries. The requested salaries, however, are at the minimum needed to attract a few candidates who have industry experience and the desire to work in public service.

- All three field based Compliance Supervisors will be assigned a State vehicle. The three new vehicles are included in the Executive Director's Office - Vehicle Lease Payments line.

- 4-wheel drive vehicles are needed to access well locations.

- Hybrid SUVs will be ordered if State Fleet's vendor can provide appropriate hybrid vehicles for use on oil and gas lease roads.

- Vehicle lease payment and variable rate paid to State Fleet is estimated at $367.35/month and $0.121/mile, respectively for hybrid SUVs for FY 08-09 - per 7/20/07 discussion with State Fleet.

- Employees will be driving temporary vehicles from State Fleet until permanent vehicles arrive; therefore the variable vehicle expenses (for mileage) will be incurred for the entire 12 months the FTE's are expected to be employed in FY 2008-09.

- Laptops (quoted in June 2007 for a Dell 520 @ $1,578) are required for employees who are frequently in the field. These field laptops must be capable of holding all data in the Colorado Oil and Gas Information System (COGIS) database and run the programs that access the data.

- For safety and business purposes, cell phones are provided for all State owned vehicles. When a vehicle is shared among several employees, the cell phone assigned to the vehicle is also shared.

Impact on Other Government Agencies:	The Department of Personnel and Administration, State Fleet, will be impacted by the three State-owned vehicles included in this request.
Cost Benefit Analysis:	The benefits of adequately balancing the development of the State's vast energy resources with the protection of the public, environment, and wildlife far outweigh the costs. According to the Colorado Energy Research Institute, the oil and gas industry's 2005 economic benefit to the state was $23 billion. It is critical for the industry's well being and the State's that the OGCC's regulations are adhered to by all oil and gas operators and that the agency has the resources to be proactive and prevent most negative impacts. It also needs the resources to detect violations, mitigate them as quickly as possible to minimize damage, and pursue the violators in a timely manner. According to the U.S. Fish and Wildlife Service's 2006 National Survey of Fishing, Hunting, and Wildlife Associated Recreation, the 2002 economic impact of hunting in Colorado was approximately $338 million (measured in 2004 dollars). The cost of this budget amendment is less than one half of one percent of this figure. If that same fraction of wildlife habitat and the economic benefits from hunting were preserved through proactive measures taken by the OGCC, the costs associated with this budget amendment would be money well spent. In addition to this benefit, this budget amendment will assist in the protection of non-game species as well as species that are or may be listed under the Federal Endangered Species Act. In this regard, this budget amendment may help keep species from being listed, which may preclude any negative economic impacts associated with a federal listing. While the OGCC believes the wildlife benefits alone justify the costs of this request, additional benefits will include better protection of the State's water resources, as well as fewer impacts to the public's health, safety, and welfare.

Statutory and Federal Authority:	C.R.S. 34-60-102(1) (2007): Oil and Gas Conservation Act – declares it is to be in the public interest to foster the responsible, balanced development, production, and utilization of the natural resources of oil and gas in the state of Colorado in a manner consistent with protection of public health, safety, and welfare, including protection of the environment and wildlife resources… C.R.S. 34-60-106(2)(d) (2007): The commission has the authority to regulate…Oil and gas operations so as to prevent and mitigate significant adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations to the extent necessary to protect public health, safety, and welfare, including protection of the environment and wildlife resources, taking into consideration cost-effectiveness and technical feasibility.

Performance Measures:

Performance Measure:	Outcome	FY 05-06 Actual	FY 06-07 Actual	FY 07-08 Approp.	FY 08-09 Request
Decrease water contamination from active oil and gas operations.					
Number of impacts to surface water, ground water, and water wells, per thousand active oil & gas wells	Benchmark	1.81	1.81	1.81	1.81
	Actual	1.81	1.97		
The OGCC needs the requested FTE to meet the benchmark or improve on it. An expected outcome of this request is a reduction in the number of impacts to the State's water resources.					

Performance Measure:	Outcome	FY 05-06 Actual	FY 06-07 Actual	FY 07-08 Approp.	FY 08-09 Request
Decrease surface disturbance caused by oil and gas activity					
Percent of reclamation inspections that comply with OGCC rules.	Benchmark	86%	86%	86%	86%
	Actual	86%	81%		
The OGCC needs the requested FTE to meet the benchmark or improve on it. An expected outcome of this request is a reduction in the size and duration of surface disturbance. Routine interim reclamation inspections and regular enforcement of violations should result in a significant improvement in the number of reclamation inspections that comply with OGCC rules.					

Performance Measure:	Outcome	FY 05-06 Actual	FY 06-07 Actual	FY 07-08 Approp.	FY 08-09 Request
Decrease in health, safety, and environmental (other than water) incidences caused by oil & gas operations.					
Total number of citizen complaints per thousand active oil & gas wells	Benchmark	9.27	9.27	9.27	9.27
	Actual	9.27	10.71		
Funding this request is essential for reducing citizen complaints. All three types of FTE's will be focused on prevention and early detection of oil and gas impacts to public health, safety, welfare, the environment and wildlife resources.					

MEMORANDUM

To: Stakeholders in COGCC Rulemaking

From: Dave Neslin, DNR Assistant Director, COGCC Acting Director

Date: November 27, 2007

Re: Initial pre-draft rulemaking proposal to implement HB 1298 and HB 1341

The following memorandum describes the initial, pre-draft rulemaking proposal prepared by the Colorado Oil and Gas Conservation Commission (COGCC) in consultation with the Colorado Department of Public Health and Environment (CDPHE) and the Colorado Division of Wildlife (CDOW) to implement House Bill (HB) 1298 and HB 1341. The purpose of this pre-draft proposal is to focus and facilitate early public input and comment on the rulemaking, which will be used to develop draft rules. The draft rules then will be subject to public notice, comment, and a hearing pursuant to the Colorado Administrative Procedures Act. The COGCC expects to adopt the final rules by July 1, 2008.

We are informally circulating the initial, pre-draft proposal to all stakeholders at this time in order to gain the benefit of stakeholder participation and feedback early in the rulemaking process. To this end, we ask that all stakeholders review this memorandum and provide us by Tuesday, December 11 with any initial comments that they wish us to consider before the proposal is posted to the COGCC website for public comment. We will review all such comments, make any appropriate revisions to the proposal, and then expect to post the proposal by Friday, December 14.

Thank you for your assistance in this important process.

Initial Pre-Draft Rulemaking Proposal to Implement HB 1298 and HB 1341

Stakeholder Review Draft

November 27, 2007

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I. INTRODUCTION

In 2007, the Colorado legislature enacted House Bill (HB) 1298 and HB 1341. HB 1298 directs the Colorado Oil and Gas Conservation Commission (COGCC) and the Colorado Wildlife Commission to "take into consideration cost-effectiveness and technical feasibility" as it "establish[es] standards for minimizing adverse impacts to wildlife resources affected by oil and gas operations" through various actions, including developing rules by July 1, 2008, that address:

- "developing a timely and effective consultation process with the [Colorado Division of Wildlife (CDOW)] governing notification and consultation on minimizing adverse impacts, and other issues relating to wildlife resources";

- "encouraging operators to utilize comprehensive drilling plans and geographic area analysis strategies to provide for orderly development of oil and gas fields"; and

- "minimizing surface disturbance and fragmentation in important wildlife habitat by incorporating best management practices" in orders and approvals.

HB 1341 similarly provides that the production of oil and gas must be "consistent with the protection of public health, safety, and welfare, including protection of the environment and wildlife resources" – a set of values hereafter collectively referred to as "public welfare and wildlife." It directs the COGCC to promulgate rules in consultation with the CDPHE "to protect the health, safety, and welfare of the general public in the conduct of oil and gas operations," and to "provide a timely and efficient procedure in which the [CDPHE] has an opportunity to provide comments during the [COGCC]'s decision-making process." The rules must be enacted by April 1, 2008, but this date may be extended by bill to July 1, 2008, and the COGCC must coordinate its rulemaking under both statutes.

Since late July 2007, the COGCC staff has consulted with the CDOW and the CDPHE to develop an initial rulemaking proposal to implement these statutes. This consultation process has included over two dozen meetings and has involved the participation of more than 30 staff members, including staff members with substantial experience in geology, hydrogeology, engineering, environmental management, information technology, mapping, wildlife biology, water quality, air quality, waste management, and epidemiology. The COGCC staff members in this process have more than 100 years of combined experience with oil and gas regulation, and many of the CDOW and CDPHE participants also have extensive prior experience with this subject and with the design and development of regulations.

As part of this process, representatives of the COGCC, CDPHE, and CDOW met in August and September with a broad range of stakeholder groups to solicit their input and participation. The stakeholder participants have included:

- Oil and gas groups and interests, including the Colorado Oil & Gas Association, the Colorado Petroleum Association, the Independent Petroleum Association of Mountain States, as well as various individual companies, such as EnCana Oil and Gas (USA), Inc., Noble Energy, Inc., El Paso Corporation, Plains Exploration and Production Company, Chevron USA, Inc., Anadarko Petroleum Corporation, Bill Barrett Corporation, K.P. Kauffman Company, Inc., and Pioneer Natural Resources, USA, Inc.;

- Environmental and wildlife groups and interests including the Colorado Environmental Coalition, Grand Valley Citizens Alliance, San Juan Citizens Alliance, Colorado Wild, Oil and Gas Accountability Project, The Nature Conservancy, Western Colorado Congress, National Wildlife Federation, Colorado Wildlife Federation, Colorado Mule Deer Association, and Trout Unlimited;

- Agriculture groups and interests, including the Colorado Cattlemen's Association, Colorado Farm Bureau, Rocky Mountain Farmers Union, Colorado Association of Conservation Districts, and the Colorado Department of Agriculture's State Conservation Board;

- Local government groups and interests, including Colorado Counties, Inc., the Colorado Municipal League, Garfield County, and Weld County; and

- Federal and state land managing agencies, including the U.S. Bureau of Land Management, the U.S. Forest Service, and the Colorado State Land Board.

Several of these participants have submitted written comments and suggestions, which the staffs of the COGCC, CDPHE, and CDOW have considered.

Based upon this work, the staffs of the COGCC, CDPHE, and CDOW have developed an initial, pre-draft proposal for the new rules. This proposal is intended to inform and facilitate initial public comment, which will be used to develop the actual draft rules. Although this initial proposal reflects considerable effort and careful consideration by the agencies involved, it will be subject to revision and refinement based on the initial public comment. It is intended to begin public dialogue regarding the scope and substance of the new rules, not to dictate the terms of those rules.

As part of this process, the COGCC will accept written and electronic comment on the proposal through at least January 31, 2008, and will hold at least one public meeting on the proposal in each of the five major oil and gas producing regions in Colorado during January 2008. The time and place for these meetings will be posted on the COGCC website. The COGCC may hold additional public and stakeholder meetings to discuss the proposal and may convene work groups to address particular issues as appropriate and as time and resources allow.

Based upon the initial public comment that is received, the COGCC in consultation with the CDOW and CDPHE expects to prepare and publish draft rules in March 2008. These draft rules will initiate the formal rulemaking process under the Colorado Administrative Procedures Act and will be subject to additional public comment and a public hearing during the Spring of 2008.

II. DETAILED DESCRIPTION

A. Proposed New Approval Process for the Location of Oil and Gas Facilities

First, the proposal would establish a new approval process for locating oil and gas facilities, which would involve a new permit, known as a Form 34 permit. Pursuant to HB 1298 and HB 1341, the Form 34 permit process would provide an effective and efficient system for addressing the site-specific surface impacts to public welfare and wildlife from oil and gas facilities in Colorado. The benefits of such a process would include: allowing operators to address the impacts on public welfare and wildlife from multiple wells in a single location; enabling the COGCC to review and address the effects of ancillary oil and gas facilities, such as tanks, compressors, access roads, gathering systems, and other pipelines; focusing the involvement of CDOW and CDPHE on those proposals with impacts of particular importance to those agencies; incorporating early protections for surface owners; increasing transparency and opportunities for public input; and expediting the issuance of drilling and waste management permits.

The proposed rules would also establish a discretionary new operator-initiated tool, known as a Comprehensive Development Plan. Such plans could be developed on a larger geographic scale and involve information that is more conceptual than a Form 34 permit, such as addressing all of the operator's anticipated development in a ten square mile area over a five year period. Informal discussions between operators COGCC, CDPHE, and/or CDOW would identify potential mitigation and avoidance measures, as well as appropriate practices and procedures for such development. If operators and consulting agencies arrive at appropriate mitigation measures, then these provisions would be included in subsequent Form 34 applications for that area and would be presumed sufficient to protect public welfare and wildlife unless new information indicates that additional or alternative mitigation is appropriate. Where an operator does not agree to the agencies' recommended mitigation measures, the mitigation would be resolved on a location-by-location basis through the Form 34 process. This process would help to expedite and simplify the Form 34 application process, allow cumulative effects to be addressed proactively, and enable mitigation measures to be developed at a larger geographic scale. By identifying sources of cumulative impacts and measures to address development impacts on a larger geographic scale, agencies and operators alike would enjoy expedited consideration of site-specific applications for permits to drill or other oil and gas operations.

Finally, the proposal would include provisions for the COGCC to initiate larger Geographic Area Plans where practicable. Where Comprehensive Development Plans would be driven by an individual operator's actions and are likely to cover a geographic area of limited size, Geographic Area Plans could be much broader in scope, covering entire gas fields or geologic basins. These Geographic Area Plans would therefore encompass the activities of multiple operators, in multiple sub-basins or drainages, over a period of ten to twenty years. It is anticipated that these Plans would lead to COGCC-driven, basin-specific rules adopted pursuant to the COGCC's rules of Practice and Procedure. This too could result in the proactive identification of cumulative impacts and mitigation measures on a larger geographic scale.

Form 34 permits, Comprehensive Development Plans, and Geographic Area Plans are described in more detail below. These processes would apply to all oil and gas activities regulated by the COGCC, but would not supersede or otherwise limit other applicable law, regulation, or requirements of the CDPHE, CDOW, and other governmental authorities.[1] These processes would apply to oil and gas activities occurring on both private and federal land, though the procedures for activities on federal land may be modified to avoid regulatory duplication or inefficiency.

1. Form 34: Application for Permit to Locate an Oil and Gas Facility

Operators would be required to submit a Form 34, Application for Permit to Locate an Oil and Gas Facility (Form 34 permit) and obtain the COGCC's approval before constructing a location for oil and gas operations. A "location" would be a definable area where an operator intends to disturb the land surface in order to locate an oil and gas facility. An "oil and gas facility" would mean all equipment used or installed at a location for exploration, production, and/or processing oil or natural gas, including a site for drilling a well or conducting drilling operations, access roads, infield oil, gas, and water pipelines, and reclamation activities.[2]

The Form 34 permit process would be designed to evaluate surface resources and address potential impacts to public welfare and wildlife from oil and gas development activities. Although operators would still be required to file applications for permits to drill (APDs), the COGCC's review of APDs would be limited to issues such as downhole engineering, safety, and correlative rights. Thus, APD issuance and other COGCC permit approvals should be substantially streamlined and expedited. As with the current process for obtaining an APD permit from the COGCC, the Form 34 permit requirement would apply to oil and gas activities occurring on State, federal, or fee lands in Colorado.

Review and approval of Form 34 applications should help to minimize the surface impacts of oil and gas development by consolidating information about proposed locations in one application, applying a set of minimum operating standards to protect public welfare and wildlife, and providing for consultation with COGCC, CDPHE, CDOW, Local Government Designees, and property owners (surface and adjacent) in certain circumstances, as described below. COGCC intends the Form 34 process to be thorough, transparent, inclusive, predictable, and efficient, in order to balance the need for energy development with the protection of public welfare and wildlife.

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[1] For example, oil and gas operations would remain subject to various existing CDPHE environmental standards and permitting requirements.

[2] The COGCC is not planning to change the definition of "oil and gas operations." See COGCC Rules, 100 Series ("**OIL AND GAS OPERATIONS** means exploration for oil and gas, including the conduct of seismic operations and the drilling of test bores; the siting, drilling, deepening, recompletion, reworking, or abandonment of an oil and gas well, underground injection well, or gas storage well; production operations related to any such well including the installation of flowlines and gathering systems; the generation, transportation, storage, treatment, or disposal of exploration and production wastes; and any construction, site preparation, or reclamation activities associated with such operations.").

Before submitting a Form 34 application, operators would be encouraged to meet or confer with COGCC staff to discuss the planned oil and gas location and identify any issues or concerns. The subsequent application requirements and review process are described below.

a. Application Requirements

The Form 34 application would include the site-specific information necessary to identify the issues associated with the proposed location, enabling the COGCC to assess all operations and their procedures, consultation requirements, and approval conditions. It would be accompanied by additional information on site conditions, access roads, waste management, production infrastructure, operations and maintenance, and bond coverage, as summarized in Appendix A. In addition, the applicant would certify that it has sent a copy of the application and the COGCC's informational brochure for surface owners to the surface owner of the location and the surface owner's lessee, if known, the record surface owners of property adjacent to and within 500 feet of the proposed location or their lessees, if known, and the Local Government Designee.[3]

A Form 34 application that is submitted without the necessary attachments or the required information would be deemed incomplete. The COGCC staff would notify the applicant of any inadequacies within 30 days of receiving the application. If the applicant fails to correct and/or supply the requested information within 30 days of that notice, the application would be considered withdrawn. After a Form 34 permit is issued, non-substantive revisions could be submitted on a Sundry Notice, Form 4. An amended Form 34 would be required for any substantive changes and for expansion of the location after interim reclamation. Such substantive amendments to a Form 34 permit would undergo the full review and approval process.

b. Notice and Comment

Operators could file Form 34 applications either electronically or on paper, but electronic filing would be encouraged. Within one week of determining that a Form 34 application is complete, the COGCC would distribute the application and all attachments to CDPHE and CDOW. In this same time period, the COGCC would post the application on the COGCC website. This would constitute public notice of the application and would initiate a 30-day public comment period. The website notice would include a link to the Form 34 application, notation of the date by which comments are due, and a link to a public comment form. All comments on a Form 34 application would be posted on the COGCC website, but the COGCC would not be required to acknowledge or respond to comments received. This comment process would not give rise to a separate final agency action which might form the basis of administrative or judicial appeal. Rather, such comments would be intended to assist the COGCC, CDPHE, and CDOW in identifying issues and concerns.

[3] This brochure would contain the rules pertaining to notice of oil and gas operations and opportunities for consultation, as well as the rules of procedure for filing complaints and applying for hearing. It would provide contact information for the COGCC's main office, field offices, and website, and it would also describe the services and information available to the public, including access to a listing of Local Government Designees.

c. Consultation

Under limited circumstances, the operator may need to consult with other parties on its proposed location. Consultation would occur between the operator, COGCC, CDPHE, and/or CDOW where an operator seeks an exception from a provision in the rules for the protection of public welfare or wildlife, or where a proposed location is in an area of high-density development, an area delineated as containing important wildlife values, or an area that could present a risk to human health or welfare. Consistent with current policy, consultation would also occur with surface owners and the Local Government Designee where the location is not subject to a surface use agreement, and such consultation would be extended to include the owners of property adjacent to and within 500 feet of the location. In all instances where consultation was required, it would occur within a 60-day period that begins on the date public notice is posted on the COGCC website. During this period, the consulting party would review the application and other pertinent information and would confer with the operator and COGCC to discuss potential impacts and mitigation measures.

i. Consultation with CDPHE and CDOW

Before an operator submits a Form 34 application, it would initially determine whether the proposed location is in an area requiring consultation with CDPHE and/or CDOW by reviewing a GIS database by quarter-quarter section, township, and range. Where consultation is required, the agency would have 60 days from the date of public notice to consult, and specific personnel would be designated for this purpose. Where a Form 34 application involves a location that is a part of an approved Comprehensive Development Plan, the consultation period would be materially shorter than 60 days, because the Comprehensive Development Plan will have established presumptive mitigation measures for public welfare and wildlife.

After reviewing the application and public input and conferring with the applicant, the consulting agencies would submit any recommended mitigation measures to the applicant and the COGCC. The applicant would indicate its acceptance or rejection of these mitigation measures. Where anyone with standing (the operator, CDPHE, CDOW, Local Government Designee, surface owner, or adjacent landowner who is directly and adversely affected) does not agree to the conditions of approval included on the Form 34 permit, any of these parties may request a hearing before the COGCC.[4] The parties to the dispute would have 15 days in which they are to confer either in person or telephonically and attempt to resolve the dispute informally. If they are unable to reach agreement, the matter would be set for consideration at the next COGCC hearing at which such matter may be heard. The COGCC would issue an order establishing conditions of approval for the application after the hearing.

Consultation between COGCC, CDPHE and/or CDOW would be required in all instances where an operator seeks an exception from a provision in the rules designed for the protection of public welfare or wildlife. Because the rules would have been determined to represent minimum

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[4] The COGCC's rules provide that "only persons who can demonstrate that they are directly and adversely affected or aggrieved by the conduct of oil and gas operations or an order of the [COGCC] and that their interest is entitled to legal protection under the act may be an applicant [for a hearing]." See COGCC Rule 503(b)(7).

standards for the protection of the public welfare and wildlife, exceptions to them could only occur after consultation with the COGCC, CDPHE, and CDOW.

Consultation between the operator, COGCC, CDPHE, and CDOW would also be required where a location is proposed in an area of high-density development. We are currently evaluating several potential benchmarks that could trigger consultation in this instance, and we seek public input on this subject. For example, existing rules provide that a "high density area" for building units is determined on a well-by-well basis by calculating the number of occupied building units within the 72-acre area defined by a 1000-foot radius from the wellhead or production facility, while for other facilities high density area rules apply when occupied buildings are located within 1,000 feet of a wellhead or production facility. See COGCC Rule 603(b), (c). The term could be defined to apply to areas where surface-density thresholds exceed 1 well pad per 160 acres, to an area in which more than 120 active wells exist within a 10 square mile area surrounding the intended new location or within a radius of 1.75 miles of the location, or areas where these thresholds would be reached by a combination of existing development and the proposed location. It is foreseeable that high-density areas would already be the subject of a Comprehensive Development Plan, discussed below. If so, field-wide mitigation measures might already be established as presumptive conditions of approval for Form 34 applications in that area.

Additionally, consultation between the operator, COGCC, and CDOW would be required for locations in areas delineated as containing important or significant wildlife values. The CDOW has initially identified those areas in which sensitive species (e.g., endangered, threatened, or candidate species) or species with important economic values (e.g., elk, mule deer, grouse) might be particularly vulnerable to impacts likely to result from oil and gas activities. Using a species ranking process similar to that used historically during the county land use planning process, and more recently used in developing High Priority Habitat maps and in evaluating U.S. Forest Service roadless areas, the CDOW has endeavored to assess the vulnerability of various species to disturbance. We seek public input on this subject and suggestions for potential areas that would be subject to consultation for this purpose.

Finally, consultation between the operator, COGCC, and CDPHE could occur when it appears, based on CDPHE's review of a Form 34 permit application, that a proposed location could present a particular risk to human health or welfare. Generally, consultation with CDPHE for proposed oil and gas locations is intended to be the exception, not the rule, occurring primarily where oil and gas activities are taking place near residences or communities. The CDPHE is likely to be involved primarily where exploration and production are occurring near residences or schools, where surface density of development puts the environment at risk, or where the potential for harm to public health is otherwise heightened. As above, we are evaluating several potential situations under which CDPHE consultation could occur and seek public input on this subject.

ii. Consultation and Onsite Inspection with Surface Owners and Local Government Designees

Since January 2005, the COGCC has required notification of, and consultation and onsite inspection with, landowners and Local Government Designees prior to COGCC approval of APDs, Form 2.[5] These existing procedures would be codified in the COGCC rules and applied during the Form 34 process rather than during the APD process. This will not increase the overall timeline for Form 34 approvals. Instead, it will ensure that any consultation with these parties occurs in conjunction with any consultation between the operator, COGCC, CDPHE, and/or CDOW. These provisions for consultation with affected surface owners would not apply on federal or Indian-owned surface lands.

Consistent with existing requirements, an operator would supply the surface owner and the Local Government Designee with a copy of the Form 34 permit application, and this requirement would be extended to apply to the owner of property adjacent to and within 500 feet of the proposed location as well. Where the location is not subject to a surface use agreement, the operator would use its best efforts to consult in good faith with the affected landowners when locating surface facilities included in a Form 34 application, and also in preparation for reclamation and final abandonment. This consultation would allow surface and adjoining owners to express preferences for the timing of oil and gas operations and reclamation activities, for example, as well as preferred locations for wells and associated facilities. The rules would provide that the requirement to consult with the landowners may be waived at any time. Local governments who have appointed a Local Government Designee would also be entitled to consultation.

Also consistent with existing requirements, a surface owner could request that the COGCC Director conduct an onsite inspection after consulting in good faith with the operator. A surface owner would be required to submit a request for onsite inspection within 10 days of the consultation described above, including proposed dates for the inspection, a description of the unresolved issues, and the surface owner's preference for having the Local Government Designee invited to participate. The surface owner would also send the request for onsite inspection to the CDPHE and CDOW, and representatives from these agencies could participate in the onsite inspection, at their election. The purpose of this inspection would be to determine whether technical or operational conditions of approval should be attached to the Form 34 permit to address crop loss or damage, as well as any potential public welfare or wildlife concerns within COGCC's jurisdiction. The onsite inspection would not address matters of surface owner compensation, property value, future property use, or any contractual issues between the operator and the surface owner.

Following the onsite inspection, the COGCC Director could apply appropriate site-specific conditions of approval to address surface owner concerns. These conditions of approval would be consistent with COGCC spacing orders and rules, and they would take into account cost-effectiveness, technical feasibility, protection of correlative rights, and prevention of waste.

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[5] See Colorado Oil and Gas Conservation Commission, Policy For Onsite Inspections On Lands Where The Surface Owner Is Not A Party To A Surface Use Agreement or Other Relevant Agreement, *available at* http://oil-gas.state.co.us/.

d. Approvals of Applications

The COGCC Director could withhold approval for any Form 34 application where the COGCC has sought to establish drilling units or to designate any tract of land as a high-density area. In such a case, the hearing would be held at the next meeting of the COGCC where the matter could be heard. The Director could also withhold or deny approval where he or she has reasonable cause to believe the proposed facility is in material violation of the COGCC's rules, regulations, orders, or statutes, or otherwise poses an imminent threat to public welfare or wildlife. Likewise, the Director could withhold approval when a valid request for a hearing is received, or based on information supplied in a written complaint submitted by a party with standing.[6] Any such withholding of approval would be limited to the minimum period of time necessary to investigate and resolve the complaint.

Where approval of a Form 34 application has been withheld or denied, an operator could ask the COGCC to issue an emergency order rescinding the Director's decision. Any hearing under these provisions would be expedited and heard at the next scheduled COGCC hearing. If, prior to the commencement of construction, the Director learned that any information submitted on the Form 34 application was false, the Director could suspend the approval.

e. Permit Appeals

The following parties may request a hearing to appeal a decision by the COGCC Director on a Form 34 permit: the operator, CDPHE and/or CDOW where consultation was required or where it occurred, the Local Government Designee, surface owners, and owners of property adjacent to and within 500 feet of the proposed location with standing. The party requesting the hearing and the operator, or the operator and the COGCC Director, as applicable, would have 15 days in which they are to confer either in person or telephonically and attempt to resolve the dispute informally. If they are unable to reach agreement, the matter would be set for consideration at the next COGCC hearing at which it could be heard. The COGCC would resolve the disputed issue at the hearing.

f. Permit Duration

It is anticipated that Form 34 applications would be filed for locations that would be constructed in less than three years. For actions that are on a longer time horizon, the applicant could group several locations and develop a Comprehensive Development Plan (see below). For this reason, where an operator fails to commence operations within 3 years from the date it obtained a Form 34, that permit would expire. This deadline could not be extended.

g. Facility Inventory

Within 30 days of installation of an oil and gas operating facility, the operator would submit a facilities inventory, Form 35, with the details of each piece of ancillary equipment on the location, including make, model, and serial number where applicable. The Form 35 facility

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6 For the definition of standing, see *supra* note 4.

inventory would include a scaled drawing showing the as-built layout of facilities and equipment on the location. Operators would be required to report any changes to the use of or equipment at an oil and gas location within 30 days of the modification. The removal or installation of such equipment would be reported on a Form 35. Within 30 days after the sale or change of the operator of an oil and gas facility, the change would be reported on a Form 10. Each location would be included in the list of wells and facilities transferred to the new operator.

h. Self-Certification of Compliance with Conditions

All operators holding Form 34 permits would be required to file with the COGCC an annual certification that the operator is in compliance with the terms of the permit, including all conditions of approval and all applicable COGCC rules and requirements. The regulation would identify the specific requirements for which self-certification is required, rather than an open-ended certification that all requirements are met. For example, self-certification of compliance may be required for stormwater management requirements, wildlife mitigation measures, or provisions for the protection of public welfare or water quality.

i. Reclamation Bonding for Oil and Gas Locations

The rules would require reclamation bonding for oil and gas locations covered by a Form 34 permit. The financial assurance could be satisfied by a financial assurance already in place for a facility such as a well or downstream gas processing facility, or it could be in the amount of $10,000 per location or $100,000 for all locations statewide. The financial assurance would remain in place until the location has been inspected and meets the reclamation standards set out in the 1000 Series rules. A certification of bond coverage would be among the items to be attached to a Form 34 application.

2. Comprehensive Development Plans

Multiple oil and gas operations in particular areas have the potential to impact cumulatively public welfare and wildlife, jeopardizing the quality of life and healthy wildlife populations on which Coloradans have come to rely. Such cumulative impacts are best addressed through advance planning on a broader geographic and temporal scale than is possible when permitting a single location.

For this reason, the proposal would include and the COGCC would encourage the submission of Comprehensive Development Plans. The Comprehensive Development Plan process would not be a public regulatory process, but rather an opportunity for operators to identify all of their anticipated development and infrastructure in an area, and then work with the COGCC, CDPHE, and CDOW to identify potential cumulative impacts and develop avoidance, minimization, and mitigation measures that address these impacts. This would be a voluntary process that is intended to facilitate discussions between agencies and operators that lead to agreement on measures that would be presumptively included in subsequent Form 34 permit approvals for locations within that area. By proactively identifying potential cumulative impacts and determining responsive mitigation measures on a larger geographic scale, agencies and operators alike would enjoy expedited consideration of site-specific applications for Form 34 permits.

a. Content of Comprehensive Development Plans

Operators would be encouraged to submit Comprehensive Development Plans early in the process and on the broadest geographic scale on which reasonable forecasts of specific surface activities might be made. We foresee an operator submitting a Comprehensive Development Plan covering its plans in an area for a three to five year timeframe, but the temporal scope and geographic extent would largely be left to the operator. A Comprehensive Development Plan may not be necessary or appropriate for small-scale operations such as wildcat wells or for operators developing a small number of wells.

A Comprehensive Development Plan would include baseline data concerning the resources present in the area sufficient to guide siting and other decisions. For example, the Comprehensive Development Plan could include a site-specific survey for species of special concern, and it could delineate critical habitats or species occurrence. It might also include baseline water quality data, as well as baseline vegetation status on the area to be disturbed or reclaimed. The Comprehensive Development Plan could describe the operator's proposed actions in the area, including all anticipated pads, access roads, pipelines, compressors, gathering stations, and other oil and gas infrastructure that is likely to be constructed in the area. It could also identify all infrastructure and development within the plan area. This baseline information would be useful to the operator and consulting agencies alike in reviewing the Comprehensive Development Plan. A Comprehensive Development Plan containing detailed information about anticipated activities and resource values present in the area is likely to be more useful in determining appropriate measures to avoid or minimize impacts to public welfare or wildlife.

b. Procedure for Comprehensive Development Plans

The operator's submission of a Comprehensive Development Plan to COGCC would trigger an informal consultation process between the operator, COGCC, CDPHE, CDOW, and the Local Government Designee. This consultation would be aimed at identifying measures that would avoid or minimize habitat disturbance, as called for in HB 1298, and that would minimize threats to public health, safety, and welfare, as called for in HB 1341. With the forecasts of development provided in Comprehensive Development Plans, the COGCC, CDPHE, and CDOW could better assess the likely cumulative impacts. For example, multiple drilling pads located in core wildlife areas could displace animals to areas with less favorable conditions, potentially causing long-term disturbance to species populations. In response, reviewing agencies could suggest mitigation measures that would minimize the possibility of cumulative impacts, such as consolidating surface facilities to minimize disruption of wildlife habitat. Likewise, they might suggest hard surfacing of roads in watershed areas, special setbacks for facilities, or seasonal timing limitations. They could also suggest mitigation to offset impacts to wildlife, such as offsite mitigation, habitat restoration, or land conservation, for those adverse impacts that cannot be avoided or minimized.

A cooperative process would be used for developing Comprehensive Development Plans, with the goal of sharing information and identifying mitigation measures that address potential cumulative impacts. It is possible that the Comprehensive Development Plan consultation process could be flexible enough to accommodate and even encourage multiple companies to come forward and share plans for an area with a goal of working together to consolidate facilities and thereby minimize costs and surface disturbance. The outcome of this consultation and negotiation would be a set of practices and conditions that would be included in and presumptively applied to Form 34 applications for locations within the Comprehensive Development Plan area where the operator agrees to the practices.[7] Where an operator does not agree to the agencies' recommended mitigation measures, the mitigation would be resolved on a location-by-location basis through the Form 34 process. Notwithstanding this consultation process for Comprehensive Development Plans, the COGCC, CDPHE, and CDOW would continue to be formally consulted parties where provided in the rules for individual Form 34 applications, but there would be a rebuttable presumption that the mitigation set forth in the Comprehensive Development Plan is sufficient to address public welfare and wildlife concerns.

3. Geographic Area Plans

Another tool for addressing cumulative impacts from oil and gas activities would be Geographic Area Plans. Unlike Comprehensive Development Plans, which are likely to cover a geographic area like a stream drainage, Geographic Area Plans would cover entire gas fields or geologic basins. Geographic Area Plans would therefore encompass the activities of multiple operators, in multiple sub-basins or drainages, over a period of ten years or more.

The Geographic Area Plan process would be initiated by the COGCC. The use of Geographic Area Plans would enable the COGCC to adopt basin-specific rules that address unique geologic or hydrologic features.[8] These new basin-specific rules would be adopted pursuant to the COGCC's Rules of Practice and Procedure, particularly Rule 529, applicable to rulemaking proceedings. That rule directs the COGCC to hold a formal public hearing before promulgating any rules or regulations, and it sets out other established procedures for the adoption of rules.

It is anticipated that the COGCC would initiate a Geographic Area Plan for a basin by publishing notice of its intent to do so. In the rulemaking process, the COGCC would require the submittal of information from both companies currently operating in the area and any companies who may seek to do so in the future. The COGCC would initiate a public participation process, including the formal public hearing required in COGCC Rule 529, and it would consult with other agencies and local governments. It is anticipated that this consultation would involve CDPHE, CDOW, appropriate Local Government Designees, county commissions, and any other agency that might appropriately bring expertise and experience to the rulemaking process.

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[7] The burden would be on the reviewing agency or others with standing to establish that mitigation measures contained in a CDP are insufficient to protect public welfare and the environment due to new information or changed circumstances occurring after the CDP was developed.

[8] Similar measures currently exist for the Wattenberg Field (see COGCC Rule 318A: Greater Wattenberg Area Special Well Location, Spacing, and Unit Designation Rule) and for the Yuma & Phillips County area of northeastern Colorado (see COGCC Rule 318B: Yuma/Phillips County Special Well Location Rule).

The consultation and public process would lead to the development of one or more scenarios for future oil and gas development in that area. These alternative scenarios would take into consideration the operators' reasonable plans for development as well as unique features, uses, or resource values found in the area. Based on the reasonably foreseeable development, the COGCC might designate units, adopt spacing orders, implement sampling or monitoring plans, or require consolidation of facilities within the area covered by the Geographic Area Plan. These measures could be included as mitigation measures for future development in that area or attached as conditions of approval on future individual Form 34 permits.

B. Collection of Data and Initiation of Health and Air Quality Studies

The COGCC anticipates entering into one or more Memoranda of Understanding (MOU) with the CDPHE in the next 90 days to initiate new studies regarding the potential direct and cumulative impacts of oil and gas activities on public health and air quality. These MOUs would address oversight, management, and joint and other funding options for these studies. One MOU would initiate a public health study that would review available literature and data in order to assess the need for follow-up toxicology and epidemiology studies of the potential risks associated with long-term, constant exposure to emissions from high-density oil and gas development. This study would begin no later than 2008. Any follow-up toxicological and epidemiological study would be managed by CDPHE in collaboration with COGCC, and the agencies would seek project partners, including The Centers for Disease Control and Prevention and the U.S. Environmental Protection Agency, to assist in its development. Information gathered as part of any such follow-up study might include: baseline health conditions; trends in health indicators and assessments of convergence of health outcomes data with plausible health impacts, based on risk evaluation of potential hazards; existing oil and health studies to identify data gaps and priority data collection needs; oil and gas complaint logs to better understand health issues for impacted populations; protocols for data-driven responses to complaints that can be used to develop meaningful health indicators through collection of individual level exposure data; and data-driven responses to complaints in order to support improved feedback and reporting to affected people. Such a large-scale human health risk assessment would help identify indicator chemicals and exposure pathways for continued health-risk based environmental monitoring.

A second MOU would initiate a cumulative air quality impact analysis for a geographic area based on anticipated regional oil and gas development and associated impacts, such as the Piceance or the DJ Basin. For example, the COGCC, in consultation with the CDPHE, other appropriate local and federal agencies, air quality modeling experts at the University of Colorado and Colorado State University and with input from stakeholders, could complete or directly support completion of a Regional Air Quality Modeling analysis to understand current and projected cumulative air quality impacts. Such modeling could reflect current baseline air quality and thereby provide a robust tool for analyzing air quality impacts from future growth and various infrastructure change scenarios. The modeling analysis could inform how various future scenarios (demographics, business growth, oil and gas development, etc.) might affect air quality and thus provide a more complete air impact analysis which illuminates the cumulative effects of all activity rather than just what is proposed by a single operator or project. The

CDPHE would manage this study, and all efforts would be made to tier the analysis to air quality impacts analyses completed or being conducted by Federal land management agencies (i.e. those associated with Resource Management Plans).

In addition, the rules would be amended to confirm the COGCC's authority to gather information needed to assess and manage cumulative effects on public health and the environment associated with oil and gas operations and to share such information with CDPHE, CDOW, and other state or local officials as appropriate. Specifically, the COGCC would have authority to collect or require the submittal of data to assist it in assessing and responding to potential effects of oil and gas exploration and production on public welfare and wildlife. Such data could include the sources, quantity, and chemical composition of products used during oil and gas operations, the fate and transport of chemicals used in oil and gas operations, produced water discharges, potential exposure pathways for human health impact evaluation, toxicity of fracturing fluids and/or their individual components, and health impacts of chemical releases to the environment. All such information obtained that is entitled to protection as a trade secret under Federal or Colorado law would be kept confidential and protected against disclosure.

As mentioned, the COGCC intends to enter into an MOU with the CDPHE to ensure effective and efficient implementation of those portions of these regulations that govern the protection of public health, welfare, and the environment. The MOU could include, among other items, procedures for responding to complaints about impacts of oil and gas operations and sharing of information.

C. Other Proposed Changes to the COGCC Rules

A number of existing COGCC rules need to be updated to reflect new issues, additional regulatory experience, and changed circumstances. In addition, several new measures to protect public welfare and wildlife would be proposed in direct response to the mandates contained in HB 1298 and HB 1341. Many of these measures are already being implemented by operators in Colorado, and we believe that they are therefore practicable and feasible.

1. <u>Changes to 100 Series</u>: Definitions

The 1000 Series would be amended to include definitions for several of the terms used in the new approval processes described above for Form 34 permits, Comprehensive Development Plans, and Geographic Area Plans. In addition, the proposal would define other new terms associated with other new provisions that would be added, as well as several existing undefined terms. For example, "stormwater runoff" would be defined to mean rain or snowmelt that flows over land and does not percolate into soil, including stormwater that flows onto a site or facility and off of a site or facility. Likewise, "solid waste" would be defined to include discarded material, including refuse or sludge from a waste treatment plant, water supply plant, or air pollution control facility. Also, several existing definitions would be revised. For example, the current definition of "multi-well pits" provides that the term includes pits used for treatment or disposal of exploration and production waste that is generated from more than one well. This definition would be revised to clarify that it applies to exploration and production waste from wells from a commonly-owned or operated lease. The definition would also clarify that "emergency pits" are those used to contain liquids not only from process upset conditions, but also from the initial phase of emergency response operations related to a spill or release.

2. <u>Changes to 200 Series</u>: General Rules

The COGCC would revise only a few of the 200 Series rules.[9] Entities involved in the production or transport of oil and gas may be required to maintain an inventory, by well or facility, of the types and quantities of all chemicals, products, and materials used or stored onsite during site preparation, well drilling, construction, completion, stimulation, and production, and to update these inventories regularly throughout the life of the well or facility. This inventory would include all substances released into the environment. Material safety data sheets, product information sheets, and other records describing chemical constituents of each product would also be maintained. The rules may also include provisions for the labeling of tanks, requiring all tanks to be labeled with the name of the operator, an emergency contact number for the operator, the tank's containment capacity and contents, and other identifying information. These new provisions would apply to any stationary vessel that is used to contain fluids, constructed of non-earthen materials such as concrete, steel, or plastic, that provides structural support.

3. <u>Changes to 300 Series</u>: Drilling, Development, Producing and Abandonment

Some current rules in the 300 Series (e.g. Rule 305 for Notices of Oil and Gas Operations, or Rule 306 for Consultation) would be eliminated because their subject matter would be addressed in the new provisions for Form 34 permits discussed above.

A new rule would provide for monitoring during well stimulation operations. This rule would require that all stimulation fluids be confined to the objective formations during treatment, and that bradenhead annulus pressure be monitored continuously and recorded during stimulation operations on all wells being stimulated. If intermediate casing has been set on the well being stimulated, the operator would also monitor and record the pressure in the annulus between the intermediate and production casings. If the bradenhead annulus pressure increases more than 100 PSIG during stimulation, the operator would notify the COGCC within 24 hours. The operator would be required to submit a Sundry Notice giving all details of the incident, including the corrective actions taken. Other changes to the 300 Series would include requiring an operator to run a cement bond log on all production casing or, in the case of a production liner, the intermediate casing, when these casing strings are run.

4. <u>Changes to 400 Series</u>: Unit Operations, Enhanced Recovery Projects, and Storage of Liquid Hydrocarbons

The 400 Series would be amended to require all wells used for an underground gas storage facility to be permitted and regulated by the COGCC. The proposal would set forth

[9] In May 2007, Governor Ritter signed HB 1180, which directs the COGCC to adopt rules to ensure accurate wellhead oil and gas measurement. Pursuant to this requirement, the COGCC is developing other regulatory amendments for this purpose. When proposed, these amendments will be the subject of a separate rulemaking process from that for HB 1298 and HB 1341.

requirements for the operation, construction, monitoring, and reporting for underground gas storage fields. COGCC approval would be required prior to drilling, repairing, or plugging and abandoning any well used for the purpose of injecting, producing, or monitoring gas contained in an underground gas storage facility.

The rules would establish that the maximum allowed storage reservoir pressure, measured in PSIG, would be no greater than 75% of the fracture gradient of the formation, and that the underground gas storage reservoir is not to be subjected to operating pressures in excess of the calculated fracture pressure. If a gas storage well fails to demonstrate mechanical integrity, the well operator would be required to isolate immediately any leaks and demonstrate that the well does not pose a threat to public welfare or wildlife. Natural gas leak detectors would be required at all gas storage wells located within 1/4 mile of an occupied residence, commercial building, assembly building, school, field office or enclosed compressor site. These natural gas leak detectors would be integrated with automated warning systems and be tested at least annually. All wells used to inject, produce, or monitor gas contained in an underground gas storage facility would be configured to provide access to the annulus between the production and surface casing to allow for the monitoring of bradenhead pressure. Bradenhead pressure for each individual well would be measured and recorded three times per week. A bradenhead pressure test would be performed at least annually during the period of maximum storage reservoir pressure on all existing gas storage wells within the boundaries of a gas storage field. Should bradenhead pressure exceed established standards, the operator of the well would immediately isolate the injection zone to contain the natural gas and demonstrate that the well does not pose a threat to the public welfare or wildlife.

Operators would submit monthly reports of the volume of gas placed into and removed from storage. The operator would also develop a storage facility safety plan including current emergency response procedures and natural gas release detection and prevention measures used by the facility. All records of natural gas leak detector testing and monitoring would be maintained for at least five years. Moreover, the operator would provide the COGCC with copies of any approval from the Federal Energy Regulatory Commission, as well as copies of any applications or reports it files with that federal agency concerning the gas storage facility or its operation.

5. Changes to 500 Series: Rules of Practice and Procedure

The Colorado Oil and Gas Conservation Act establishes that any person who violates any provision of the Act, any rule or order of the COGCC, or any permit is subject to a penalty not exceeding $1,000 per day that such violation continues. C.R.S. 34-60-121(1). COGCC's 500 Series includes a rule setting out a base fine schedule for violation of rules listed. See COGCC Rule 523. These rules would be amended to update this schedule, increasing fines, where appropriate, to reflect inflation and increased attention to the need to comply with COGCC rules in order to protect public welfare and wildlife. In addition, rules to include the CDPHE and CDOW would be proposed, such that these agencies would be given standing to participate in the COGCC hearing process for appeals to establish drilling and spacing units and to allow increased well density.

6. <u>Changes to 600 Series</u>: Safety Regulations

We anticipate changes to this series to reflect provisions in HB 1341. In addition to codifying provisions for testing sampling of coalbed methane wells and monitoring activities near coal outcrops that are already applicable in the San Juan Basin, the proposed rules would include new provisions to address odor issues associated with the siting of certain types of oil and gas facilities, resource conservation, stormwater management, and water quality protection and coalbed methane.

a. Odor Management

The proposed rules would include setbacks and control equipment for production equipment and produced water pits. For example, glycol dehydrators located within 1/2 mile residences and schools would be required to utilize a control device achieving a minimum 98% reduction in VOC emissions. Also to protect the public from odors, produced water pits within 1/2 mile of a residence or school would be required to be enclosed in a tank, and produced water and other production tanks located within 1/2 mile of a residence or school would be required to use an emission control device achieving 98% reduction in VOCs. The rules would also require that flared gas be directed to a controlled flare or other combustion device capable of 98% destruction efficiency. These control devices and operating parameters would be reflected in a duly-authorized emissions permit issued by the CDPHE Air Pollution Control Division.

The rules would also provide that oil and gas operations must be in compliance with the CDPHE Air Quality Control Commission regulation concerning odor emissions. More specifically, the rules may state that no oil and gas operation may cause or allow the emission of odorous air contaminants from any single source such as to result in detectible odors which are measured in excess of established objective limits. For example, for areas used predominantly for residential or commercial purposes, it would be a violation if odors are detected after the odorous air has been diluted with seven or more volumes of odor-free air. For other land use areas, it would be a violation if odors are detected after odorous air has been diluted with 15 or more volumes of odor-free air. The rules would further provide that rule violations may not be cited provided that the best practical treatment, maintenance, and control measures are being utilized in order to maintain the lowest possible emission of odorous gases. In determining the best practical control methods, the COGCC would not require any method which would result in an arbitrary and unreasonable taking of property, or in the practical closing of any lawful oil and gas operation, if such method would be without corresponding public benefit. The rules would also provide that COGCC technical staff be odor certified, and that odor complaints would be investigated by COGCC staff, odor-certified county or local health inspectors, or odor-certified CDPHE inspectors.

b. Resource Conservation

The proposed rules would require that well drill operations and well workovers utilize green completion practices where power supply and process flow lines and associated equipment or devices are reasonably available for such purpose. For this purpose, green completion practices means the process of directing initial flow during flow drilling and well completion to specifically designed surface equipment, and by using a sand separator to reduce flaring and venting at the well site. In addition, the rules would require operators to use low-bleed or no-bleed pneumatic valves (or natural gas activated valves) in all new relevant gas service associated with oil and gas operations.

c. Stormwater Management

The new rules would reiterate that an oil and gas construction site that disturbs more than one acre, or that are part of a larger common plan for development exceeding one acre, must be in compliance with the State of Colorado Water Quality Control Division stormwater regulations and any applicable CDPHE stormwater construction permit.

The new rules would also require oil and gas facilities to establish Facility Spill and Runoff Control Programs during post-construction operations. These provisions would apply to well facilities, roads, culverts/stream crossings, pads, pipelines, compressor stations, etc. during the post-construction operation and reclamation of the exploration and production facilities. The programs would be implemented through plans that would include commitments to use mitigation measures to control pollutants associated with the facility. The Facility Spill and Runoff Control Program would include a description of the potential pollutant sources that may reasonably be expected to affect the quality of discharges associated with the ongoing operation of oil and gas facilities during the post-construction operation and reclamation of the facilities. Various pollutant sources would be addressed, including transport of chemicals, fueling of vehicles or equipment, disposal of waste, erosion and vehicle tracking from well pads, and unanticipated leaks and spills. The Facility Spill and Runoff Control Program would identify and describe appropriate operating practices that would be implemented at the facility to reduce the potential for pollution from the sources identified above. Measures could include:

1) **Covering materials and activities and stormwater diversion:** Operators would minimize contact of precipitation and stormwater runoff with materials, wastes, equipment, and activities with potential to cause stormwater pollution;

2) **Materials handling and spill prevention:** Operators would implement procedures and practices for material handling and spill prevention for materials used, stored, or disposed of that could result in stormwater pollution;

3) **Erosion prevention:** Operators would prevent erosion from unpaved areas, including well pads and road surfaces;

4) **Preventive Maintenance:** Operators would implement a preventive maintenance program that includes inspection and maintenance of operations, facilities, and operating practices to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to surface waters;

5) **Good Housekeeping:** Operators would implement a good housekeeping program for maintenance of clean, orderly operations and facilities. This program would include and address cleaning and maintenance schedules and waste disposal practices;

6) Spill Response Procedures: Operators would implement procedures for responding to and cleaning up spills; and

7) Vehicle Tracking Control: Operators would implement practices to control potential sediment discharges from vehicle tracking. These practices could include designing and maintaining roads and pads to minimize rutting and tracking, minimizing site access, street sweeping or scraping, tracking pads, washing racks, educating employees, or other management practices for sediment control.

The rules would also include provisions applicable to Primary Facilities such as vehicle maintenance facilities, facilities located in or within a tributary of State Water designated as an "Outstanding Water" by the Colorado Water Quality Control Commission, or facilities located in an area determined and identified by the COGCC where additional protection of the water resource is necessary to maintain the quality of surface waters within the tributary watershed.

d. Sampling and Monitoring for Coalbed Methane Development

The proposed rules would provide for statewide application of monitoring requirements currently contained in various COGCC orders (e.g. Order 112-156, 112-157) that are specific to coalbed methane development in the San Juan Basin. These orders are available on the COGCC website. The rules would thus include provisions requiring water well sampling, coal outcrop and coal mine monitoring, and bottomhole pressure monitoring.

7. Changes to 700 Series: Financial Assurance

The proposed rules would contain various amendments to refine the 700 Series for financial assurance. For example, the rules would require a financial assurance in an amount equal to the estimated cost to ensure proper reclamation, closure, and abandonment of a centralized exploration and production waste facility. Elsewhere, the rules would increase specific dollar amounts needed for financial assurance, as reflected below.

	Current Amount	Proposed Amount
For soil protection and plugging & abandonment for wells less than 3,000' in depth	$5,000 per well	$10,000 per well
For soil protection and plugging and abandonment for wells more than 3,000' in depth	$5,000 per well	$20,000 per well
Statewide assurance if operator has fewer than 100 wells in Colorado	$30,000	$60,000
Statewide assurance if operator has more than 100 wells in Colorado	$100,000	$200,000
Natural gas gathering, processing, or underground storage facilities	$50,000 statewide	$50,000 per facility
Small gas gathering, processing, or underground systems (gathering or processing less than 5 MMSCFD)	$5,000	$25,000 per facility
Operators of Class II Underground Injection Control wells		$50,000 per facility

The proposed rules would provide that these increases would be prospective only.

The proposed rules may clarify provisions for the statewide "emergency reserve" of unobligated funds. For instance, they could provide that the two year average of the unobligated portion of the statewide Environmental Response Fund be maintained at a level not to exceed $4 million dollars, and that the COGCC ensure that there is an adequate balance in the fund to address environmental response needs.

8. <u>Changes to 800 Series</u>: Aesthetic and Noise Control Regulations

The proposed changes to the 800 series would require operators to employ management practices for the control of fugitive dust if located within 1/4 mile of a residence, an educational facility, assembly building, hospital, nursing home, board and care facility, jail, or designated outside activity area. Management practices to control fugitive dust could include speed restrictions, regular road maintenance and watering, and restriction of construction activity during high wind days. The Director, through the Form 34 permit process and also as a result of consultation with CDPHE and CDOW, could require additional BMPs such as road surfacing, wind breaks and barriers, and automation of wells to reduce truck traffic. The rules would additionally provide that any oil and gas operator engaged in clearing or leveling land, or any owner or operator of more than five acres of land that has been cleared in attainment areas, or one acr3e in non-attainment areas, and from which fugitive particulate emissions will be emitted, would be required to use all available and practical methods which are technologically feasible and economically reasonable in order to minimize such emissions in accordance with the requirements of Section iii.d of the DPHE Air Quality Control Commission Regulation No. 1 emission control for particulate matter 5 CCR 1001-3.

Finally, the rules would provide that the Director, through the Form 34 permit process and consistent with the operator's right to conduct operations, may require operators to employ site-specific mitigation practices to protect aesthetic and visual resources. Such practices could include selecting paint colors that allow long-term facilities to blend in with the natural landscape background; siting of roads, well locations, and production facilities to minimize visual impacts; reducing unnecessary disturbance; modifying production facility or well pad shape or size; using low-profile pumping units and low-profile tanks; and completing interim reclamation of disturbed lands.

9. <u>Changes to 900 Series</u>: Exploration and Production Waste Management

The 900 Series would be amended to expand the resources to be protected from oil and gas exploration and production waste to include public welfare and wildlife. At this point, the COGCC is likely to focus on engineering matters regarding individual exploration and production pits, rather than addressing permitting matters more generally for centralized or commercial waste management facilities.

The rules would be amended to eliminate reference to the Sensitive Area Determination Decision Tree currently found in Rule 901(e), replacing it with directives to use geologic and hydrogeologic data to evaluate the potential for impact to ground water and surface water, including percolation tests that demonstrate that seepage will not reach underlying ground water or waters of the state. In addition to the current prohibition on drilling pits constructed on fill material, the proposed rules would state that unlined pits may not be constructed in areas where pathways for communication with groundwater or surface water are likely to exist.

In conformity with revisions of definitions in the 100 series, the rules would clarify that multi-well pits include those used for treatment or disposal of exploration and production waste generated from more than one well from one commonly owned or operated lease. The rules would also provide that a Form 15 permit application must be submitted to the COGCC for production pits, certain special purpose pits, and drilling pits designed for use with fluids containing concentrations exceeding 10,000 ppm total petroleum hydrocarbon or chloride concentrations at total well depth exceeding 15,000 ppm. The rules would provide for the lining of drilling pits meeting these criteria.

The rules would include a provision requiring that flared gas must be directed to a controlled flare or other combustion device capable of 98% destruction efficiency, as discussed above. They would also include a new measure stating that well stimulation flow back operations must implement reduced emission completion technologies where they are cost effective and technically feasible.

a. Pit liners

The rules would be amended to provide that production pits must be lined, unless the operator supplies substantial evidence that the quality of the produced water is equivalent to that of the underlying aquifer, or the operator can clearly establish by substantial evidence (such as percolation tests) that seepage will not reach the underlying aquifer or waters of the state. Moreover, drilling pits designed to be used for drilling and completion of three or more wells would be lined. The rules would double the thickness required for soil liners from six to twelve inches after compaction, and they would increase from twelve to twenty mils the minimum thickness for synthetic liners.

The rules would retain the provision that emergency pits constructed during initial response to mitigate spills or releases are not subject to the lining requirements; however, they would add provisions stating that these pits must be closed and remediated as soon as the initial phase of emergency response is complete or process upset conditions are controlled. The rules would also contain provisions for the closure of tank batteries, multi-well pads, compressor stations, gas plants, and underground injection control facilities.

b. Spills and Releases

For all reportable spills from exploration and production pits, the operator would be required to make good faith efforts to notify and consult with the affected surface owner or the surface owner's appointed tenant prior to commencing remediation operations. The rules would also set out a new table of soil standards to which operators must remediate spills or releases. To control the extent of releases, the rules would provide that secondary containment must be constructed sufficient to contain the contents of the largest single tank in the bermed area plus sufficient freeboard to contain any precipitation.

c. Waste Management

The rules would be amended to provide that records of the transportation and disposal of waste must be kept for at least five years, and that they must be signed by the generator, transporter, and receiving facility. The rules may also prohibit the roadspreading of produced water if TDS levels exceed 3,500 mg/l. The rules would additionally state that flowback fluids may not be used for dust suppression. Finally, the rules would include a provision for the disposal of exploration and production waste not covered by existing categories. This "other" exploration and production waste would include workover fluids, pit sludge, tank bottoms, pigging wastes from gathering and flow lines, and natural gas gathering, processing and storage wastes.

10. Changes to 1000 Series: Reclamation Standards

The 1000 Series would be amended to shorten the time period after operations cease for an operator to complete interim reclamation on non-crop land. The amendments would also provide that areas needed for continuing production operations be compacted, covered, paved, or otherwise stabilized in such a way as to minimize dust and prevent erosion. Drilling pits would have to be reclaimed no later than three months after the conclusion of drilling and completion activities. For areas no longer in use, interim reclamation would be considered complete when all ground surface disturbing activities at the site have been completed, and all disturbed areas have either been built on, compacted, covered, paved, or otherwise stabilized in such a way as to prevent erosion. Alternately, interim reclamation would be considered complete when a uniform vegetative cover has been established with an individual plant density of at least 70% of pre-disturbance levels, excluding noxious weeds. Reseeding alone would not be sufficient to demonstrate completion of interim reclamation.

The COGCC also proposes to modify provisions for the final reclamation of well sites and associated production facilities. First, removal of all equipment, supplies, and waste material from the site would be required, and the burning or burial of such material would be performed only in accordance with applicable local, county, state, or federal solid waste disposal regulations. Final reclamation would be considered complete when a uniform vegetative cover has been established with an individual plant density of at least 70% of pre-disturbance levels, excluding noxious weeds.

11. Proposed 1200 Series: Wildlife Operating Standards

As described more fully in Appendix B, the new rules would contain a set of detailed Standard Operating Practices (SOPs) for the protection of wildlife that would be applicable to Form 34 permits. These SOPs would be designed to address potential surface impacts of oil and gas activities on wildlife resources, and they would be applicable to every Form 34 location and apply for the life of a facility. Many of these SOPs would apply to all locations in the state, while some would apply only to locations in certain geographic areas. These SOPs would be minimum requirements that must be employed during location, construction, operation, and reclamation of all oil and gas facilities that they cover. It is anticipated that different measures may apply to different stages of oil and gas development. For instance, some SOPs may apply at to pre-development planning, others may apply to the drilling and production stage, and still others may apply to post-development reclamation.

Because SOPs would have been determined by rule to represent minimum standards for the protection of the public welfare and wildlife, an operator seeking an exception to an SOP must demonstrate either that the operating standard is not necessary to protect public welfare or wildlife, or that it may achieve equivalent protections for these values with an alternative measure. As described above, the rules would provide that requests for such an exception from SOPs would trigger consultation between the operator, COGCC, CDOW, and/or CDPHE.

In addition, the rules are likely to contain a set of detailed Best Management Practices (BMPs) designed to minimize or mitigate the impact of oil and gas activities on wildlife resources. These BMPs would be recommended for all oil and gas locations, in order to minimize the potential for adverse impacts to resources from oil and gas activities. Moreover, BMPs could be required on a site-specific basis for an oil and gas location as a result of consultation between the operator, COGCC, CDOW and/or CDPHE, as described above. In these circumstances, the BMPs would be used to minimize or mitigate potential impacts associated with the proposed oil and gas development that are not adequately addressed by the SOPs.

APPENDIX A

Requirements for a Form 34 Application

In addition to a completed Form 34 application form, operators seeking approval to construct a location for oil and gas operations would be required to submit:

1) A current 8 1/2” x 11” scaled drawing of the section (or sections) containing the proposed facility location including:

- Dimensions on adjacent exterior section lines sufficient to describe the quarter section containing the proposed facility, along with field-measured distances of the proposed facility to the nearer section lines, measured at 90° from the section line to the well location;
- Ground elevation and legal land description by section, township, range, principal meridian, baseline and county;
- A complete description of any monuments or collateral evidence found, with description of all aliquot corners used;
- A site plan and construction layout drawing, showing layout during construction, operation, and post-operation phases; proposed drainage patterns; any diversion or containment structures; any roads, fencing, tanks, pits, buildings, or stock piles proposed on the site;
- All visible improvements within a specified distance of the proposed facility, with a horizontal distance and approximate bearing from the proposed facility location. This is to include all buildings, roads, utility lines, pipelines, mines, oil or gas wells, water or injection wells, standing bodies of water, and natural channels; and
- All surface uses within a specified distance of the proposed facility;

2) An aerial photo showing the proposed location and a 3-mile radius;

3) A USGS 1:24,000 topographic map with at least a three-mile radius from the proposed facility and access roads which shows the route of all access roads from public roads;

4) A location cross-section plot, showing both the original slope and the cut-and-filled slope of the proposed location during construction, operation, and post-operation phases;

5) If the location is to be used as a multiple well pad, a multi-well wellbore trajectory drawing with bottom-hole locations;

6) An Access Road Construction Plan, showing:
 - a) Type and size of all roads;
 - b) Drainage and stream-crossing details; and
 - c) Scaled construction drawings;

7) A vegetative analysis, including:
 - a) NRCS map unit vegetation analysis of all disturbed areas;
 - b) Baseline vegetative transect of all disturbed areas;
 - c) Wetlands/Riparian delineation, including:
   - i) Map (800-meter buffer);
   - ii) Jurisdictional wetlands survey; and
   - iii) Corps of Engineers 404 permit, if required;

8) An NRCS soil map unit description;

9) A wildlife survey (800-meter buffer)

10) A detailed description of any off-site mitigation

11) A Waste Management Plan, including a detailed plan for:
 - a) Exploration and production waste;
 - b) Hazardous/solid waste; and
 - c) Human waste;

12) A detailed list of all production infrastructure to be located at the site;

13) A Construction and Ongoing Operations and Maintenance Plan, including:
 - a) Reclamation and Monitoring Plan;
 - b) Noxious Weed Control and Monitoring Plan;
 - c) List of Proposed BMPs (by media) and BMP Inspection Schedule;
 - d) Access Road Maintenance Plan; and
 - e) SPCC Plan and Inspection Schedule;

14) A certification of bond coverage;

15) A certification that the operator has sent a copy of the Form 34 application to the owner of the surface estate underlying the proposed location, the owners of land adjacent to the proposed location, and the LGD;

16) A determination of whether the location is in an area of high-density development or in an Environmentally Sensitive Area;

17) If a variance from Standard Operating Practices would be requested, a basis for the request; and

18) Other information required by the regulations or otherwise included by the operator at its discretion (e.g. a Comprehensive Development Plan and/or associated informally development protection and/or mitigation measures);

APPENDIX B

Operating Standards for Protection of Wildlife and its Habitat

The Colorado Division of Wildlife (CDOW) is evaluating a variety of operating standards to implement HB 1298 and its mandate to "establish standards for minimizing adverse impacts to wildlife resources affected by oil and gas operations." C.R.S. 34-60-128(3)(d).

A. Standard Operating Practices

The first set of operating standards would be Standard Operating Practices (SOPs), which would function as management measures applicable to large geographic areas. These SOPs would be incorporated by rule and applied to locations just as any other applicable provision in the rules. The term "Standard Operating Practices" would be defined in the rules to reflect that they are technologies, tools, and procedures that, when applied, avoid or minimize the impacts of oil and gas on public welfare and wildlife, and particularly on wildlife habitat. The SOPs in the rules would be applicable to every Form 34 location, both in areas where CDOW is to be consulted and in areas where consultation is not triggered. The proposal would provide that SOPs are mandatory unless they are modified by an exception granted by the COGCC after consultation with COGCC and CDOW, and they would apply for the life of the facility.

It is envisioned that many SOPs would apply to locations in all areas of the state, while others would apply only to certain geographic resource areas. The rules may provide that each river basin in Colorado would be a defined geographic area for purposes of certain SOPs, or it may use another method of delineating geographic boundaries. These geographic resource areas would be identified on a map available on the COGCC and CDOW websites.

Three categories of SOPs are likely to apply to various geographic resource areas in the proposed rule: general operating standards, seasonal timing limitations, and no surface occupancy areas. Each of these categories would identify minimum requirements that apply to various stages of the oil and gas development process: pre-development planning, drilling and production, and post-development reclamation.

The rules are likely to include a set of general operating standards for various stages involved in drilling for and production of oil and natural gas. For example, during pre-development planning, operators could be required to maintain a geospatial database or other method of tracking ongoing activities and outlining the status of reclamation efforts. They could also be required to map critical habitats within a certain distance of planned facilities to identify and properly permit those sensitive resource areas. They could also be required to stabilize all exposed road surfaces in order to control or prevent erosion or siltation, as well as maintain the normal flow of water in all streambeds or drainage channels. During the drilling and production phase, operators could be required to control the spread of noxious weeds by developing and implementing weed management plans and sanitizing the undercarriage of vehicles on the site. They could also be required to develop a food and waste management plan for each facility, incorporating measures that will minimize conflicts with wildlife. At the post-development phase, operators could be required to immediately reclaim all roads not to be retained for future use, including closing the road to traffic, removing all bridges and culverts, restoring natural drainage patterns, reshaping cut and fill slopes, replacing topsoil, and revegetating disturbed surfaces.

The rules could also include various seasonal timing limitations as SOPs necessary for the protection and sound management of certain species as well as restrictions on surface occupancy in certain areas in order to protect important wildlife habitat. The precise contours of these measures would be determined by COGCC and CDOW after further study and consultation with stakeholders and the public.

B. Best Management Practices

The rules are also likely to contain a set of detailed Best Management Practices (BMPs) that would be designed to further minimize or mitigate the potential impacts to wildlife beyond the protections afforded by the SOPs discussed above. These BMPs would be recommended for all oil and gas locations, in order to minimize the potential for adverse impacts to resources from oil and gas activities. Application of BMPs would be strongly encouraged for inclusion as management measures in Comprehensive Development Plans. They could also be recommended on a site-specific basis for an oil and gas location as a result of consultation between the operator, COGCC, CDOW and/or CDPHE. In these circumstances, the BMPs would be used to minimize or mitigate any impacts associated with the proposed oil and gas development that are not adequately addressed by the SOPs.

The BMPs would also include measures more specific to individual stages of oil and gas development. For instance, while planning for projects in areas of sensitive wildlife habitat, operators should plan to consolidate production facilities so as to minimize impacts to wildlife, and, where geologically and technically feasible, maximize the number of wells from the same pad. Operators should also plan to minimize noise from their activities by equipping vehicles with mufflers or other noise suppression systems and by enclosing and insulating compressors. Once they have entered the drilling and production phase, operators should endeavor to use pitless drilling or "closed-loop" systems, where drilling fluids are stored in tanks rather than in earthen pits. Operators should also take steps to minimize vehicle trips on roads to minimize the adverse impacts on wildlife from road construction and use. Operators could also partner with resource agencies and local user groups to identify existing and potential wildlife-related recreation activities in areas of production and development. Once development is completed, operators should conduct interim reclamation on all disturbed areas not needed for active support of production operations in order to control erosion and nonnative plant invasion. With regard to vegetation, operators should evaluate a two-stage approach in which they first establish native grasses for weed competition and erosion control and then establish forbs. They should also work closely with CDOW or affected landowners to establish and implement a monitoring program to assess the impacts of development activities and mitigation and reclamation efforts.

The BMPs could also include several species-specific mitigation prescriptions which address the specific needs of key species of concern and their habitats. These prescriptions could include operational practices such as gating roads to reduce traffic disruptions, using bear-proof trash receptacles and dumpsters, or limiting seismic or construction activities during certain periods of the year. As above, these measures would be determined by COGCC and CDOW after further study and consultation with stakeholders and the public.

Included in the BMPs would be general mitigation measures that offset unavoidable or non-negotiable impacts. For example, operators unable to avoid impacts on wetlands may participate in funding wetland banking programs. Operators may also voluntarily offer to fund off-site habitat mitigation projects or prescriptions to improve big game forage away from development sites, or they may use off-site mitigations such as relocating or repairing trails.

COLORADO OIL & GAS CONSERVATION COMMISSION ORGANIZATION

Attachment B

- **Executive Director** H. Sherman
  - **Acting Director** D. Neslin
    - Executive Asst. J. Missey
    - COMMISSION
    - **Information Technology Manager** M. Fine
      - Data System IT Prof V T. Kerr
        - Permit Supr. Phys Sci Tech III D. Ahlstrand
          - Permit/Compl Tech Phys Sci Tech II J. Stanczyk
          - Permit/Compl Tech Phys Sci Tech II V. Walker
          - Permit/Compl Tech Phys Sci Tech II A. Fischer
          - Permit/Compl Tech B. Yokley
          - Permit/Compl Phys Sci Tech II L. Coler
        - Surety Admin. Program Asst II M.Choury
      - IT Prof III K. Robertson
      - Network Admin. IT Prof I J. Glossa
      - GIS Administrator Phy Sci Res/ Scientist II J. Milne
      - Info. Processing Supervisor T. Ikenouye
        - Imaging Sys Admin Admin Asst III M. Ramos
        - Records Admin. Technician II L. Sevall
        - Records Admin. Technician II M. Greenstein
        - Records Admin. Technician II C. Sundseth
        - Prod/Levy Analyst Data Spec I D. Geimausaddle
        - Prod/Levy Analyst Data Spec I E. Rivera
    - **Hearings Manager** T. Beaver
      - Enforcement Officer C. Harmon
      - Hearings Officer II New as of 7/1/07
      - Hearings Assistant M. Humecki
    - **Financial Manager** W. Schultz
      - Accountant I R. Ou
      - Admin Asst Admin Asst III A. Gipson
    - **Engineering Manager** D. Dillon
      - Engr. Supr. Prof Eng II D. Shelton
        - South Area Engr. Eng. In Training II D. Sutphin
        - S. Central Insp. Trinidad Phys Sci Tech II J. Duran
        - SE Insp. Cheyenne Wells Phys Sci Tech II M. Leonard
        - SW Insp. Durango Phys Sci Tech II L. Melton
        - SW Area Engr.. Durango PE I Mark Weems
      - Engr. Supr. Parachute Prof Eng II J. Adkins
        - NW Area Engr. Parachute Eng In Training II K. King
        - NW Area Insp. Parachute Phys Sci Tech II J. Krabacher
        - NW Area Insp. Parachute Phys Sci Tech II D. Graham
        - NW Area Insp. Rifle Phys Sci Tech II Vacant
      - Engr. Supr. Prof Eng II D. Andrews
        - North Area Engr. Eng in Training II Denver D. Burn
        - N. Wattenberg Weld Co. Insp. Phys Sci Tech II E. Binkley
        - NE Inspector Sterling Phys Sci Tech II K. Lively
        - S. Wattenberg Weld Co. Insp. Phys Sci Tech II J. Precup
        - Engineering/ Enviro Tech B. Koehler
    - **Environmental Manager** D. Baldwin
      - Envir. Supervisor Envir Prot Spec III M. Ash
        - Envir. Specialist Envir Prot Spec II S. Lindblom
        - Southeast Area Envir Prot Spec II P. Gintautas
        - Southwest Area Envir Prot Spec II K. Spray
      - Envir. Supervisor Envir Prot Spec III R. Ferguson
        - Envir. Specialist Envir Prot Spec II B. Chesson
        - Northeast Area Enviro Prot Spec II J. Axelson
        - Northwest Area Enviro Prot Spec II C. Canfield

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